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# SCREENING REPORT, CRUDE OIL AND NATURAL GAS PRODUCTION PROCESSES

PROCESSES RESEARCH, INC.

PREPARED FOR
ENVIRONMENTAL PROTECTION AGENCY

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# SCREENING REPORT

# CRUDE OIL AND NATURAL GAS PRODUCTION PROCESSES

## FINAL REPORT

## TASK ORDER NO. 13

## CONTRACT NO. 68-02-0142

DECEMBER 27, 1972

PREPARED BY

PROCESSES RESEARCH, INC.

INDUSTRIAL PLANNING AND RESEARCH

CINCINNATI, OHIO

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## ABSTRACT

There are about 600,000 to 700,000 producing oil and gas wells and about 800 natural gas processing plants in the United States. The field separation equipment serving these wells and the natural gas processing plants emit pollutants to the atmosphere. In 1971, an estimated total of 7,000 to 18,000 tons per day of hydrocarbons, about 20,000 tons per day of sulfur oxides, and about 52 tons per day of sulfides (as $H_2S$) were emitted. It is estimated that 90 percent of the field processing equipment has adequate emissions control. Technology is available for 100 percent control; however, economics are not favorable for recovery of hydrocarbon losses from small production fields in remote locations. This report presents information on the processes used in producing crude oil and natural gas, the location and production rates for the existing production facilities, applicable air pollution control regulations, the processes used in reducing air pollution from oil and gas processes, and methods for testing and analysis of air contaminant emissions.

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## SECTION I - INTRODUCTION AND SCOPE

Production of gas and oil involves the loss (emission) of hydrocarbons and sulfur-bearing compounds into the atmosphere. The objective of this study is to provide background information on such production. The study summarizes the types of field processing in use, the source and magnitude of the emissions, and methods available for reducing them.

## SECTION II - SUMMARY

This study was conducted by surveying available literature and by consultation with people in some of state agencies concerned with control of air pollution from oil and gas production.

Crude oil and natural gas are produced in 31 states of the United States. In 1971 there were 805 natural gas processing plants located in 24 different states and 280 counties. In 1969 there were about 520,000 producing oil wells and about 114,500 producing natural gas wells. A majority of these wells are located in 258 major oil fields and 38 major gas fields. There are about 3,000 companies engaged in the production of crude oil and natural gas.

It is estimated that, in the United States, between 7,000 and 18,000 tons per day of hydrocarbons are emitted to the air in the production of crude oil and natural gas. The $SO_x$ emissions are estimated to be 20,000 tons per day, while sulfide emissions are estimated to be 52 tons (as equivalent $H_2S$) per day.

The burning and emission of hydrocarbons in the field has been drastically reduced in recent years because of regulations by state conservation departments, and because it was to the economic advantage to the companies to recover such hydrocarbons.

## SECTION III - DETAILED DISCUSSION

### A. OBJECTIVE

The objective of this study is to provide background information on facilities for crude oil and natural gas production, and the atmospheric emissions from those facilities and their control. Numbers in parentheses refer to the applicable references in Appendix H.

### B. FIELD PRODUCTION OF CRUDE OIL AND NATURAL GAS

The composition of crude oil and natural gas at the well head varies from field to field. Each well produces some or all of the following components:

Parafinic hydrocarbons; e.g., methane, ethane, propane and highers
Napthenic hydrocarbons; e.g., cyclohexane
Nitrogen
Helium
Carbon dioxide and hydrogen sulfide, which are acid gases
Water or salt water
Combined sulfur compounds; e.g., COS and RSH
Oxygen

The wells are classified as gas wells or oil wells based on the ratio of oil/gas produced. For example, Texas law defines an oil well as "....any well which produces one (1) barrel or more of crude petroleum oil to each one hundred thousand (100,000) cubic feet of natural gas." (20). A gas well is one which has an oil/gas ratio less than that quoted.

Field processing is required to separate the well head stream where both liquids and gases are present. Also, the quantities of oil and gas produced are measured in the field. Any natural gas produced is either fed to a gas collection line, recompressed and recycled to the producing strata to maintain pressure, or, in remote areas, it may be burned at the well head. Any

crude oil produced goes to a refinery or to a crude oil pipeline. Any liquid water produced is either a waste product or is returned to the formation for repressuring.

Natural gas is classified as "dry gas" or "wet gas." Dry gas is defined as gas that contains no hydrocarbons heavier than methane or ethane (57). Wet gas, or casing-head gas, contains hydrocarbons from methane through pentanes. Natural gas is also classified as either "sweet gas" or "sour gas." Sweet gas is defined as gas which contains little or no hydrogen sulfide, while sour gas contains varying amounts of hydrogen sulfide (57). Texas law (20) defines a sour gas as one containing more than 1-1/2 grains of hydrogen sulfide or more than 30 grains of total sulfur per 100 cubic feet. These variations and the fact that the gas may also contain carbon dioxide, helium, and/or water vapor means that each natural gas plant is designed to process the particular gas mixture it receives.

C. PROCESSES USED AND ATMOSPHERIC EMISSIONS THEREFROM

1. Introduction. A block flow sheet showing the relationship of the crude oil field separation process to that of the natural gas process is presented on Flow Sheet E-1 of Appendix E. Flow Sheet E-2 of Appendix E shows a block flow sheet for the field processing of dry natural gases.

2. Field Separation Processes for Crude Oil and Wet Natural Gas. Flow Sheet E-3 of Appendix E is an overall flow diagram showing the major steps used in field separation processes (49). One process train may serve only a single well, all wells on the same lease with common ownership, or all wells in a field.

The latter case is referred to as a unitized field; i.e., one where all wells are operated by a single operator for all of the owners of the field.

The first step in the field separation process for crude oil is the "water knockout" where any liquid water is removed. To facilitate this separation, an emulsion-breaking step (not shown) is frequently required ahead of the knockout. Emulsion-breaking is accomplished by adding a chemical and/or by heating. If liquid hydrocarbons separate out they are transferred to a tank at the well head (lease tank) or to the gas-oil separator. The gas from the water knockout goes to the gas-oil separator.

The gas-oil separator is used to separate crude oil or natural gas liquids from the gas and to recover the gas at as high a pressure as possible. This is usually accomplished in three gas-oil separation tanks in series. Each succeeding tank operates at a lower pressure than the previous tank. Each reduction in pressure results in a separation of liquids and gas. This separation occurs because the mutual solubility of the gas and liquids is lower with lower pressure. The liquids which separate out go to the lease tank, operating at atmospheric pressure. At this point, residual gases dissolved in the liquid flash off and are vented to the air if the tank is open. Vented gas is lost unless it is recovered by vapor emission controls system. Vapor emission controls are not shown on Flow Sheet E-3, but are discussed in Section III H.

The above-described gas-oil separation process is used where well head pressure is several hundred psi. At many wells, the pressure is much lower, and hence, fewer than three stages are used. At some locations, the

well head pressure is very low and all gas is removed in the water separation step; thus, no separate gas-oil separator is used.

The crude oil collected in the lease tank goes to a refinery. At some locations, this crude oil is treated before it leaves the field to remove water or $H_2S$.

The gas which leaves the process usually goes by pipeline to either a gas processing plant or to sales, or it is recycled to maintain field underground pressure. At remote locations where recycling is not practiced or where it is not economical to sell the gas produced, it is burned (flared).

Flares, where they exist, and hydrocarbon vapors from vented lease tanks are the chief source of emissions.

3. Field Processes for Dry Natural Gas. Dry natural gas is field processed either if it contains liquid water or water vapor which will freeze in the pipeline or if it contains acid gas. As shown on Flow Sheet E-1, gas which contains water passes through a water knockout and then through a gas dehydrator, employing either glycol absorption or desiccant adsorption. Acid gases are then removed in the sweetening process. The $H_2S$ removed either goes through a Claus sulfur plant or, if the quantity is small, it is usually flared.

4. Natural Gas Processes. The purpose of natural gas processing plants is to separate ethane, methane, propane and/or natural gasoline, and to produce a dry natural gas for sales. A usual sales specification for natural gas is a gross heating value of not less than 1,000 Btu per cubic foot, a maximum of 0.25 grains of $H_2S$ per 100 scf, with a maximum of 20 grains total sulfur

(Private Communication 7 in Appendix I), and a water content low enough so that line freeze-ups will not occur.

Flow Sheets E-1 and E-2 of Appendix E show some of the process arrangements used. The steps used are: (1) Acid gas treating, if required, with or without the Claus sulfur plant (if a Claus plant is not used, the acid gases are burned to convert the $H_2S$ to the less toxic sulfur oxides before venting); (2) gas dehydration; and (3) gas separation. The gas separation step separates the entrained hydrocarbons. Variations exist in the process arrangements shown; e.g., some plants have the acid gas treating step after the dehydration step and some treat the natural gas after it leaves gas separation.

The gas fractionation process steps may be carried out at different locations; e.g., one plant will separate the gas into a natural gas stream and a liquids stream containing the $C_2$'s and heavier fractions, which liquids stream is then fractionated at another plant.

There are seven acid gas treating processes commonly used in the United States. These are listed in Table 1. The description of these processes is not a part of this report. They all produce a sales specification natural gas with respect to the acid gas content and an acid gas stream containing $H_2S$ and $CO_2$ with only traces of hydrocarbons.

TABLE NO. 1

COMMERCIAL ACID-GAS TREATING PROCESS IN U.S.

IN NATURAL GAS SERVICE (12)

| Process | No. of Plants | Gas Rate Scfd | Special Features |
|---|---|---|---|
| Benfield | 18 | | Used for gases containing 75 percent $CO_2$ and $H_2S$ |
| Diglycolamine or Econamine | 15 | >1,000,000,000 | Used to remove COS and RSH, as well as $CO_2$ and $H_2S$ |
| Fluor Solvent | 6 | | Used for gases with high concentrations of $CO_2$ and $H_2S$ |
| Girbitol or MEA | >200 | | This is the most commonly used process |
| Molecular Sieves | >12 | >1,000,000,000 | Used on low acid gas concentrations (<100 grains $H_2S$/100 cubic feet) and for RSH removal |
| Selexol | 6 | >900,000,000 | Used on high $CO_2$ with low $H_2S$, especially when $H_2S$ goes to Claus |
| Sulfinol | 37 | | Used on wide range of $H_2S$ and $CO_2$ concentrations |

The gas dehydration step is either a glycol injection process, described below as part of the refrigerated absorption process, or a solid desiccant process, described below under the refrigeration process.

In the gas separation step, there are eight processes used in the United States. These processes are absoption, refrigerated absorption, refrigeration, compression, adsorption, fractionation, cryogenic, and turbo-expansion. The name of the process with the exception of the fractionation

process, is derived from the step used to separate the ethane and heavier hydrocarbons from the natural gas feed. The process descriptions which follow and the respective flow sheets shown in Appendix E, present either the basic step for separating natural gas from a liquids mixture or a complete plant process. Where only the basic separation step is presented, it should be realized that any given plant may have any or all of the steps shown on Flow Sheets E-1 or E-2, together with a complete distillation train, in addition to the basic process step.

a. Absorption Process. This process is used to remove natural gasoline, LPG (liquified petroleum gases, mixed ethane, propane and butane) from a wet natural gas, as shown on Flow Sheet E-4 in Appendix E. The gas from the field passes through an absorber where an absorber oil removes the propane and heavier molecules. The residue gas, consisting chiefly of methane and ethane, is sold as natural gas. The enriched absorber oil goes to a stripper which separates the absorbed propane and heavier molecules from the absorption oil. The gas stream of propane and heavier molecules goes to the stabilizer where methane and ethane are driven off and recycled to the absorber. The remainder (bottoms) from the stabilizer goes to a splitter, a distillation column, where the LPG comes off as the overhead product while natural gasoline is the bottoms product. Appendix A indicates that 164 plants in the United States use an absorption process. A well designed and operated plant has no atmospheric emissions, except for an occasional leak or other mechanical failure. The natural gasoline is usually stored in tanks. Where these tanks are vented, they

lose (emit) hydrocarbons to the atmosphere due to breathing and filling. The cost of these losses can be as much as several thousand dollars per year for each tank. Most tanks are equipped with emission controls as an economic measure to control losses. Emission controls for tanks are discussed in Section III H.

b. Refrigerated Absorption Process. A flow sheet of a refrigerated absorption process plant, which was started up in 1970, is shown on Flow Sheet E-5 of Appendix E (24).

In this process, the incoming gas is dehydrated to a minus 40F dew point. This is accomplished by bringing the incoming natural gas into contact with triethylene glycol to absorb the water vapor. The glycol is regenerated by boiling off the water. At some plants, this water vapor leaves the process as steam and carries glycol at less than 0.5 pounds per 1,000,000 cubic feet of gas processed into the atmosphere. After dehydration, the gas passes through two absorbers in series at minus 40F. All hydrocarbons except methane are absorbed by oil in the first absorber. A sponge oil regenerator recovers the hydrocarbons which were absorbed in the second stage absorption. These recovered hydrocarbons are mixed with the rich oil from the first stage absorption and fed to the primary demethanizer. The overhead gases from the demethanizer return to the absorber. The bottoms go to a rich-oil demethanizer where any remaining methane is removed as fuel gas. The rich oil then goes to a still where the balance of the absorbed hydrocarbons are distilled off, thus regenerating the first stage absorber oil. The overheads from this still are fractionated in two steps to produce ethane, propane and a $C_4+$ hydrocarbon stream for sales. There

are no deliberate emissions from this process, although there may be some breathing and filling losses from the $C_4$+ liquid storage tankage. Refrigerated absorption is used by 448 plants in the United States.

c. Refrigeration Process. The refrigeration process plant is shown on Flow Sheet E-6 of Appendix E (27). In this process, the inlet gas is dried to a dew point of minus 120F, using molecular sieve beds. Water vapor is adsorbed on the bed. Two beds are used in parallel, arranged so that one is on-stream while the other is being regenerated (not shown). Regeneration is accomplished by means of heat and a stream of hot gas. The hot gas from the bed being regenerated is cooled to condense the water and is then fed to the operating bed. The dry gas from the molecular sieve is then passed through a heat exchanger where it is cooled to minus 35F. Liquids which condense are removed in a separator. The gas from the separator is cooled to minus 135F and passes through a second separator where more condensed liquids drop out. The gas from this separator then passes back through the two heat exchangers countercurrent to the incoming gas, where it exchanges heat with (cools) the incoming feed gas. The liquids from the two separators are fed to five distillation columns in series where methane, ethane, propane, isobutane, normal butane and natural gasoline are recovered as separate products. The only emissions from this process are leakage and storage tank breathing and filling losses.

d. Compression Process. The basic elements of a compression process step are on Flow Sheet E-7 of Appendix E. This process uses two stages of compression, each followed by cooling and gas oil separation, to produce a wet

natural gas product and natural gasoline. Less than 3 percent of the plants listed in Appendix E are indicated as using compression processes.

e. Adsorption Process. The flow sheet of this process (Flow Sheet E-8 in Appendix E) shows the steps used to obtain a natural gas product and a mixed hydrocarbons product. The resulting liquids product is fed to a fractionation process.

The basic process consists of two or more beds of activated carbon. The beds are used alternately, with one or more beds on-stream while the others are being regenerated. The activated carbon adsorbs all hydrocarbons except methane. The bed is regenerated by means of heat and steam, which remove the adsorbed hydrocarbons as a vapor. This vapor is then condensed permitting the water to be separated from the liquid hydrocarbons. About 12 percent of the existing natural gas plants listed use an adsorption process. Hydrocarbon emissions to the atmosphere may occur at the condenser and from vented liquid storage. The amounts of these emissions depends on how the equipment is operated and whether or not emissions controls exist. See Section III H for a discussion of emission controls.

f. Other Processes. Less than 2 percent of the plants listed use processes other than the five processes previously described.

There are 13 plants which are listed as using fractionation processes. These processes separate natural gas liquids into the various hydrocarbon fractions using distillation as described in Subsection III C 4 c. above, and shown on the bottom half of the Flow Sheet E-6. The feed to these plants is a mixed liquid from another plant.

One plant uses a turboexpansion process. This process is similar in principle to that of the gas-oil separator step discussed under Subsection III C 2. The difference is that turboexpanders are used to control the pressure reduction of the gas. These expanders recover a portion of the pressure energy in the gas which is otherwise lost when pressure reduction is effected by means of a control valves.

Another process used is cryogenic in nature. This process is used to recover helium from natural gas. No flow sheets are presented for this process as it is of relatively minor importance in the industry as a whole.

g. Miscellaneous. The literature search disclosed two processes related to the production of crude oil and natural gas that can serve as sources for and contribute to $H_2S$ and sulfur-oxide emissions.

The first process involves the secondary recovery of crude oil by use of water flood. In this process, water is pumped into an oil-bearing stratum to push oil to the pump intake of an oil well. In some fields in Texas, the water used is a sour water (contains $H_2S$) obtained from a different stratum in the oil field than that producing the oil. $H_2S$ and sulfide are stripped from this water by countercurrent contact with an oxygen-free gas. The sulfides removed are ultimately flared. The reason for removing the sulfides from this water is to prevent the sulfides from contaminating the sweet oil and gas being recovered from the oil stratum.

Two installations are known (31)(32). One installation flares 2 tons per day of sulfur (equivalent to 4 tons per day as $SO_2$). The other

installation flares about 2.5 tons per day of sulfur (5 tons per day $SO_2$). The bibliography, with one of the two articles, indicates that there may be other installations of this type.

The second process is not related to crude oil and natural gas except that it affects the processing of natural gas. Texas law (20, pages 18, 19 and 20) permits the use of sour gas under certain restrictions in the manufacture of carbon black. No effort was made to determine how much gas is used for this purpose, or how much sulfur oxides are emitted to the air from plants using sour gas in making carbon black.

D. LOCATION OF PRODUCTION FACILITIES

Crude oil and natural gas is produced in 31 states of the United States (see Appendix C).

A list of the natural gas processing plants in the United States and Canada appears yearly in the Oil and Gas Journal. The list, as of January 1, 1972, shows 805 plants in the United States (3) located in about 280 counties in 24 different states. This list was retabulated by states and counties and appears in Appendix A. This tabulation shows the number of plants in each county, total gas throughput, total gas capacity and other information for these plants.

Preparation of a list of field processing facilities for crude oil and natural gas proved to be impractical. No such tabulation, or data from which such a tabulation could be made, was found in the literature.

As noted in Subsection III C 2., page 4, a facility may serve a single well, a group of wells, or all of the wells in a field. One source lists about

542,000 oil wells and about 114,500 gas wells in the United States in 1969 (19, Table 1052, page 643 and Table 1056, page 645). An attempt to make a list of all the oil fields (or a list of the 258 major oil fields and 38 major gas fields) and their location, was attempted using the API crude oil pipeline maps (17 and 18) and published lists of the major oil and gas fields by states in the United States (4 and 5). This attempt was abandoned because many of the major oil fields could not be located by county or counties. A list of oil and gas producers is published every two years. The 1966-67 list gave names of about 3,000 producing companies in the United States with their mailing addresses (58). However, there was no information provided on specific locations of these facilities.

E. PRODUCTION - PAST FIVE YEARS AND ESTIMATED FUTURE FIVE YEARS

The number of natural gas processing plants has diminished in recent years while their total gas capacity and throughput have increased. As of January 1, 1970, there were 839 plants with a capacity of 67,900.7 MM cfd and an average throughput of 56,216.3 MM cfd (59) while as of January 1, 1972, the number of plants had diminished to 805 while the total capacity and throughput had increased to 75,137 MM cfd and 58,997.3 MM cfd, respectively (3).

A table of "Crude Petroluem Produced in the United States" for the years 1966 through 1970 appears in Appendix C, while a table of "Marketed Production of Natural Gas in the United States" for the same five years appears in Appendix D. These tables list the production by states in the United States. No estimates were found for the next (future) five years, although an estimate

is available for the year 1972 for the United States as a whole (5, page 140). Therefore, estimates were made for each state for the year 1975, by extrapolating the trend for the past three to five years as modified by other available information for some of the states (55, 60, 61 and 62). These estimates show decreases in crude oil production in all states except Alaska, Louisiana, and Mississippi, with an overall decrease in the production for the United States as a whole. The Alaska increase is predicated on the completion of the pipeline to the Prudhoe Field, while Louisiana and Mississippi may be at their peak now. The only states showing real increases in natural gas production are Alaska, Louisiana and Texas. The increase for the first two states, if it comes, will be the result of an anticipated installation of facilities to market gas presently being flared. Information received from the Texas Railroad Commission indicates that in 1971 the gas produced was at or above the estimated figure given for 1975. Texas oil fields are presently being operated at their capacity and total production will go down as these fields are depleted. The present downward trend in production in the United States could be reversed if large new fields are discovered in the future. However, any new fields will require new processing facilities.

F. ESTIMATES OF NATIONWIDE AIR CONTAMINATE EMISSIONS

The major portion of air contaminate emissions from production of crude oil and natural gas are hydrocarbons and sulfur oxides. The lesser portion of such emissions are hydrogen sulfide and glycols. No information has been obtained which will permit the making of a reliable estimate of the quantity of any of the above contaminants. However, it is possible to make rough estimates.

1. Estimated Hydrocarbon Emissions. An order-of-magnitude estimate of the total hydrocarbon emissions from the production of crude oil and natural gas in 1969 can be made from a table in "Minerals Yearbook, 1969" (63, page 744). This table indicates that in 1969 about 526 billion cubic feet of natural gas was vented and flared in the field production of oil and gas and at gas processing plants in the United States. A large percentage of this gas is flared. If we assume that 75 to 90 percent of this gas is flared and that the gas vented without flaring had a density of 0.1 pounds per cubic foot, then between 7,000 and 18,000 tons per day of hydrocarbons were vented. This estimate can be checked by separate calculations for field emissions and for natural gas plant emissions.

For an estimate of the natural gas plant emission, another table in "Minerals Yearbook, 1969" (63, page 740) was used. This table indicates that in natural gas processing plants, an estimated 41.9 billion cubic feet of gas were vented and flared and an estimated 54.6 billion cubic feet of gas were unaccounted for. The following assumptions were used:

a. All the unaccounted-for gas is lost to the atmosphere.

b. Twenty percent of the vented and flared gas is emitted without burning.

c. The emitted hydrocarbons have a density of 0.1 pounds per cubic foot. These hydrocarbons will be mainly methane, ethane, propane, and butanes.

Calculations using the above estimates and assumptions indicate that unburned hydrocarbons emitted to the atmosphere for the 54.6 billion cubic feet per year unaccounted-for losses amount to 7,500 tons per day of hydrocarbons.

Assuming that 20 percent of the 41.9 billion cubic feet reported as vented and flared was vented without burning, an additional 1,100 tons per day of hydrocarbons would be emitted. This gives total unburned hydrocarbon emissions from natural gas plants of 8,600 tons per day or about 10 to 11 tons per day per plant.

In estimating the hydrocarbon emissions in field processing, three literature articles (41, 42, 44) were used. These articles related to vapor recovery systems for field processing tanks. Examples were given for five vapor recovery systems, recovering between 40 and 125 cubic feet per barrel of crude oil processed. The average for the five cases was 96.5 cubic feet per barrel. The following assumptions were used to calculate the emissions:

a. Vapor recovery systems reduce potential emissions by 90 percent.

b. The 10 percent uncontrolled production emits 96.5 cubic feet of hydrocarbons per barrel of crude oil produced.

c. The density of the vented hydrocarbons is 0.1 pounds per cubic foot.

Based on these assumptions and the fact that 3.37 billion barrels of crude oil were produced in 1969 (Appendix C), it is estimated that 4,100 tons per day of hydrocarbons were emitted in field processing.

The total for field emissions and gas plant emission is 12,800 tons per day which compares favorably with the 7,000 to 18,000 tons per day estimated at the start of this subsection.

It has been estimated (71) that the loss by evaporation in producing and storing crude oil and other petroleum products amounts to 2 to 3 percent of the total crude oil produced. This amounted to 26,000 to 38,000 tons

per day in 1969. Of this, less than one third (8,200 tons per day) is lost in field production. The remainder is lost in refining and in distribution of products to the consumer. The production losses are generally in areas far from large population centers, while the losses in refining and distribution are generally in or near such centers.

2. Sulfur Dioxide Emissions. In the production of crude oil and natural gas, sulfur dioxide is emitted as a result of the following:

a. Field flaring or burning of waste gases containing sulfur.

b. Flaring of hydrogen sulfide from gas sweetening processes having no Claus sulfur plant.

c. Burning of waste gases from Claus sulfur recovery plants.

d. Flaring of hydrogen sulfide from the sweetening of sour water used for water flooding in secondary oil recovery.

e. From the vent stacks of carbon black plants that burn sour gas.

A study of the last two sources is not included in this report.

In order to obtain an accurate estimate of the sulfur oxide emissions from the first three sources, the following information is required:

a. The rates of production and the hydrogen sulfide and total sulfur content of the natural gases from the major oil and gas fields which produce a significant quantity of sour gas.

b. A list of all natural gas sweetening plants and the quantity and sulfur content of the feed gas.

c. A list of all Claus sulfur recovery plants which process acid gases from natural gas sweetening, including the quantity of sulfur fed and the plant efficiency.

A search of the literature and consultation with Government Bureaus in six states (Appendix I, Items 5 through 11) produced very meager information on the sulfur content of natural gases. The available data are tabulated in Table II. The gas rates shown are design rates for gas sweetening plants. Information is available on the natural gas production in 1971 from major gas fields in the United States (5, page 211). The total accounts for less than 20 percent of the total amount of natural gas produced in 1971. No list of the natural gas sweetening plants has been obtained. A list of Claus sulfur recovery plants appears in a report prepared for the Environmental Protection Agency (70, page C1). Sixty-four of these plants which were built prior to 1970 are listed as processing acid gases from natural gas sweetening. Only the sulfur capacity of these plants was given. Thus, there is inadequate information to prepare a reliable estimate of the total sulfur oxides or hydrogen sulfide emissions.

A rough estimate of sulfur dioxide emissions has been made by using the following assumptions:

a. The 64 sulfur plants using acid gas feed from natural gas sweetening operated at 65 percent of their total production capacity.

b. These plants operated at an average sulfur recovery efficiency of 90 percent (Reference 70 indicates that Claus plants have efficiencies between 89 and 97 percent).

TABLE II

SULFUR CONTENT OF NATURAL GASES

| State | County | Field | $H_2S$ Grains 100 cf | RSH Grains 100 cf | Design Gas Rate MM Cfd | Reference (Appendix and Item No.) |
|---|---|---|---|---|---|---|
| Texas | Ward | Lockridge | 6.35 | 0.75 | 150 | H-25 |
| Texas | Hemphill | Buffalo Wallow | 27.0 | 0.2 | 50 | H-25 |
| Texas | | Washita Creek | 19.0 | - | 150 | H-25 |
| Arkansas | | Magnolia | 1500 | - | - | I-12 |
| Arkansas | | McKamie-PaHun | > 1500 | - | - | I-12 |
| Texas | Hunt | Quinan | 0.1 Percent | - | | H-46 |
| New Mexico | | Monument | 0.38 Percent | 15 | | |
| Texas | | New Hope | 14 Percent | - | 50 | H-64 |
| Texas | | Oates | 8 | - | 130 | H-65 |
| Texas | | Terrell Plant | 220 | 3 | 220 | H-67 |
| Texas | | Gray Ranch | 1 | - | 275 | H-66 |
| Texas | | Gomez | 8 | - | 250 | H-66 |
| Texas | | Puckett | 0.2 Percent | - | 180 | H-68 |
| Florida | Escambia | Jay | 11 Percent | - | 35 | H-1 and H-2 |
| Texas | | Buffalo Wallow | | | | |
| | | (Hunton) | 18-30 | | - | H-21 |
| | | (Morrow) | 0.26 | | - | H-21 |

c. The average sulfur content of all gas produced in the United States is 0.5 mole percent.

d. All gas marketed in 1969 required sweetening to below 0.25 grains per 100 cubic feet (less than 0.0005 mole percent).

The sulfur oxides emission from Claus sulfur plants were calculated as follows: the 64 Claus plants had a sulfur capacity of 3,270 long tons per day. At 65 percent of capacity, the possible production would be 2,120 long tons per day. The sulfur loss at 90 percent efficiency calculates to 240 long tons per day, or about 538 short tons $SO_2$ per day emitted by Claus sulfur recovery plants associated with natural gas production.

Sulfur oxides emissions from gas sweetening plants having no Claus plant were calculated as follows: 20.7 trillion cubic feet of gas was marketed in 1969. This quantity of gas, at 0.5 mole percent sulfur, contains 11,900 short tons of sulfur per day. From this was subtracted the 2,380 short tons (2,120 long tons) of sulfur per day fed to Claus plants leaving 9,520 short tons of sulfur per day flared to produce 19,040 tons of sulfur dioxide per day. The sulfur in 526 billion cubic feet of natural gas vented and flared, assuming 0.5 mole percent sulfur, is 320 short tons per day. Subtracting the 50 tons sulfur per day as $H_2S$ emissions, calculated in next section, leaves 270 tons of sulfur burned per day to produce 540 tons of sulfur dioxide per day.

Hence, the total sulfur dioxide emitted per day in the production of crude oil and natural gas is 538 plus 19,040 plus 540, or 20,118 (say 20,000) tons.

3. Hydrogen Sulfide Emissions. No information was obtained to permit the making of a reliable estimate. However, the hydrogen sulfides emissions can be approximated by using numbers previously calculated and assuming that the 85 billion cubic feet of gas emitted in field processing contains 0.5 percent sulfur. This calculates to an estimated 52 tons (as equivalent hydrogen sulfide) emitted per day.

4. Glycol Emissions. To estimate the triethylene glycol emission rate, information is required as follows:

a. The number and capacities of plants which use glycol dehydration, and which vent the water vapor produced.

b. The amount of triethylene glycol per million cubic feet of gas processed vaporized with the water produced.

This information has not been obtained, so the following assumptions have been made on which to prepare an estimate:

a. One fourth of all gas marketed in the United States is dehydrated by use of the glycol process.

b. All plants using the glycol process vent the water vapor produced.

c. Half of all of the glycol lost in the process is emitted with the water vapor while the other half is entrained with the gas processed.

Using these assumptions, together with the reported maximum glycol loss of 0.1 gallons per million cubic feet of gas processed (69), it is estimated that a national total of about 7 tons of TEG is emitted per day by the glycol dehydration processes.

## G. APPLICABLE STATE AND LOCAL LAWS AND REGULATIONS

A condensation of the applicable sections from the state air pollution control laws and regulations for the states which produce crude oil and/or natural gas are tabulated in Appendix G. This information was abstracted from the publication "Environmental Reporter, BNA, State Air Laws." (54) This publication listed regulations for 26 of the 31 states which produce oil and gas; however, it did not include local regulations. Of the 26 states that have regulations, 17 issued such regulations since January 1, 1972. No attempt was made to obtain local regulations. The magnitude of the job of surveying several hundred counties where crude oil and gas is produced is beyond the scope of this project.

In addition to state air pollution control regulations, the production of crude oil and natural gas is subject to state conservation laws and regulations. Telephone calls were made to the conservation departments of the states of California, Louisiana, and Oklahoma and to the Railroad Commission of Texas. (Appendix I, Items 1, 2, 3 and 4). These four states produce 78 percent of the crude oil in the United States. Three of these states prohibit the venting or flaring of gas from gas wells except under special conditions. They prohibit or limit the amount of gas that may be vented or flared from oil wells. Oklahoma has no laws or regulations prohibiting venting or flaring. The Oklahoma Division of Conservation discourages the wastage of large quantities of gas. Economics usually dictate whether or not individual producers vent gases.

The effect of the Texas regulations and the realization by producers that it was to their economic advantage to recover gas instead of wasting it

was to reduce the percent of the gas vented and flared in that state from 5.59 percent in 1953 to 0.74 percent in 1971. Prior to 1953, the quantity of casinghead gas that was vented or flared was not reported.

H. PRACTICAL EMISSION CONTROLS

The technology exists for control of hydrocarbon emissions. The decision to install required control equipment is usually based on economics. Equipment for vapor conservation may include floating roof tanks, diaphragm tanks or vapor recovery systems. Whenever a tank is vented, emissions will occur to the atmosphere due to tank "breathing." Most crude oil contains gas dissolved under considerable pressure. Vapor recovery is used to save the gases which are released from solution when the pressure on the hydrocarbon liquid is reduced.

Two vapor recovery systems are in general use and are shown on the flow sheet in Appendix F. The first system is used where the lease tank cannot be sealed, as is frequently the case in older fields where wooden tanks were installed because the crude oil is corrosive due to high sulfur content. This vapor recovery system consists of a vessel, known as "gas boot," which receives the crude oil from the oil-gas separator and is maintained at atmospheric pressure. Vapors and gas which flash from solution in the gas boot are collected, compressed, cooled and fed to a knockout vessel. The dehydrated gas from the knockout vessel goes to a natural gas pipeline. Liquids from the gas boot and the knockout go to the lease tank. The second system is used where the lease tank can be made vaportight. The vent from the lease tank serves as a suction pipe for a compressor. The compressed gases and vapors are cooled and pass to a knockout vessel. The gas from the knockout vessel goes to a natural gas

pipeline. Liquids from the knockout are returned to the lease tank. A pressure-controlled bypass line is installed between the compressor discharge and suction lines to prevent the creation of a vacuum in the lease tank when no vapors are being generated therein.

Hydrogen sulfide tends to come out of the solution in the crude oil with the light hydrocarbon gases. Its emission is controlled when those of the light hydrocarbon are controlled. The hydrogen sulfide is separated when natural gas is sweetened. Where state regulations do not prohibit, many plants burn the hydrogen sulfide removed from the gas to produce less odorous and less toxic sulfur dioxide, before discharging to the atmosphere. Other plants have installed modified Claus sulfur plants to convert the hydrogen sulfide to sulfur, which is sold. Claus plants convert about 89 to 96 percent of the sulfur in the gas to elemental sulfur. The percent recovery depends on the sulfur concentration of the gas fed to the Claus unit and on the number of reactor stages used (70, page 9). The waste gas from the Claus unit is burned in an open flare to convert hydrogen sulfide and other sulfides to sulfur dioxides.

Sulfur oxide emissions result from the burning of sulfur-containing waste gases. To reduce these emissions requires use of a Claus tail gas process before incineration or scrubbing of the gases after incineration. The Beavon Sulfur Removal Process and the Cleanair Sulfur Process are claimed to increase the sulfur recovery for Claus processes to 99.9 percent (70, page 2). The IFP Process is claimed to increase sulfur recovery to 97 percent (70, page 3). These processes and flue gas scrubber processes are either relatively new or still being developed.

## I. PLANTS WITH BEST EMISSION CONTROL METHODS

In plants having good control of emissions, most of the crude oil field processes have vapor-emission control systems on the field lease tanks. It is economically advantageous at such plants to recover these vapors. In addition, it is required by state conservation regulations. Many of these systems were installed at the time that a field became unitized. The literature (2, 26, 30, 41, 42, 43, 44) reports six locations where vapor emissions control are used; namely:

Sun Oil Company

Jay Field, Florida

Shell Oil Company

Cedar Creek Anticline, Montana
Little Beaver Field, Montana
Little Beaver East Field, Montana
Block 24 and 27 Offshore Fields, Louisiana

Cities Service Oil Company

Devonian Formation Field, Texas
Dora Roberts Ranch Field, Texas
(Three of eleven fields had installations in 1965, others were being studied)

Humble Oil & Refining Company

King Ranch, Four Field Area, Texas

Gulf Oil Company

Various West Texas Fields, Texas

## J. AVAILABLE METHODS FOR TESTING AND ANALYSIS OF AIR CONTAMINANT EMISSIONS

Methods for testing and analysis of air contaminant emissions for crude oil and natural gas processes are listed in Appendix B. These methods appear to be satisfactory and further R&D does not appear to be warranted.

## K. RESEARCH AND DEVELOPMENT NEEDS FOR EMISSION CONTROL EQUIPMENT

Equipment to control hydrocarbon emissions is adequate and no need for further research is indicated. Three processes are presently available to reduce $SO_x$ emissions. The cost of installing and operating these processes in their present form cannot be justified economically. Research and development might result in cost reduction.

The estimates of hydrocarbon and sulfur-oxide emissions presented in this report are very crude, because of lack of information. To obtain more accurate estimates, an extensive industry survey would be required to quantitatively determine types and capacities of field processing equipment used, existence, type and efficiencies of vapor recovery systems used, existence, type and efficiencies of gas sweetening processes used, sulfur analysis of gas from each well, gas and oil production rates, methods for disposal of sulfur recovered, and similar information.

## L. ESTIMATED COSTS FOR EMISSION CONTROL

The following costs, based on information in Reference 41, are for a vapor recovery system using a gas boot (see System 1, Section III H). The compressor discharges to a gas gathering system operating at 30 to 60 psig. The costs have been escalated to 1972 levels and scaled up for plants having a vapor rate of 500 mcfd and 1,000 mcfd.

| Mcfd of Vapor Recovered | Installed Cost Dollars |
|---|---|
| 100 | 10,000 to 13,000 |
| 500 | 22,000 to 28,000 |
| 1,000 | 33,000 to 43,000 |

The costs for systems with closed field tanks and no boot would be about $1,000 less at 100 mcfd to $3,000 less at 1,000 mcfd.

Many systems in Texas operate on closed field lease tanks and discharge to a 15 psig sales line. These systems consist of a compressor with an automatic control system and have no condenser or knockout. At 1972 prices, an installation would cost about $6,000 for a recovery of 30 mcfd of vapors (41).

Most of the vapor recovery systems reported in the literature for large systems were installed in conjunction with other processing improvements and the costs reported for these systems do not segregate the costs of vapor recovery.

Costs for Claus sulfur plants and tail gas processes for Claus plants are given in Reference 70. These plants would be installed as additions to those gas sweetening plants that are presently burning the hydrogen sulfide produced.

For a typical Claus plant having a capacity of 100 long tons of sulfur daily, the investment and sulfur production costs for various acid gas concentrations are approximately:

| Mole Percent $H_2S$ In Acid Gas Feed | Claus Plant Investment Dollars | Sulfur Production Cost Per Long Ton Dollars |
|---|---|---|
| 15 | 1,400,000 | 14 |
| 50 | 1,000,000 | 11 |
| 90 | 900,000 | 9 |

The product sulfur capacity has a pronounced effect on costs of Claus plants. For typical plants using 50 mole percent $H_2S$ feed gas, the investment and sulfur production costs for various capacities are approximately:

| Product Sulfur Daily Capacity (Long Tons) | Claus Plant Investment Dollars | Cost Per Long Ton Dollars |
|---|---|---|
| 10 | 300,000 | 26 |
| 100 | 1,000,000 | 11 |
| 1,000 | 4,300,000 | 8 |

For those plants that must attain a 99 plus percent sulfur recovery, the investment and operating costs for adding a Beavon Sulfur Removal Process are about equal to the cost for the Claus plant alone, while the costs for adding an IFP process will be about 50 percent greater than the costs for a Beavon Process.

These costs are for the control systems only. Where gathering lines are involved, total costs become much higher. Isolated oil wells may be hundreds of miles from sulfur removal facilities. In such cases, oil is now usually pumped to a lease tank and hauled to a buyer by truck, while the gas and hydrogen sulfide from the well is usually burned in a flare.

# APPENDIX A - NATURAL GAS PROCESSING PLANTS IN UNITED STATES, JANUARY 1, 1972

# NATURAL GAS PROCESSING PLANTS IN UNITED STATES, JANUARY 1, 1972*

| STATE COUNTY | COUNTY POP. 1960 | TOTAL NUMBER OF PLANTS | TOTAL GAS CAPACITY MM CFD | TOTAL GAS THRU-PUT MM CFD | NUMBER OF GAS RECYCLE PLANTS | RECYCLE PLANTS CAPACITY MM CFD | SULFUR RECOVERY PLANTS NUMBER | SULFUR RECOVERED LT/DAY | TYPE OF PROCESS[a] AND NUMBER[b] OF PLANTS USING EACH PROCESS. A | B | C | D | E | OTHER | NOT AVAIL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALABAMA | | | | | | | | | | | | | | | |
| MOBILE | 314,300 | 1 | 2.0 | 1.3 | 0 | | - | - | | | 1 | | | | |
| ALASKA | | | | | | | | | | | | | | | |
| KENAI BURDUGH | - | 2 | 45.0 | 34.2 | 1 | 5.0 | - | - | | | 2 | 1 | | | |
| ARIZONA | | | | | | | | | | | | | | | |
| APACHE | 30,400 | 1 | 2.5 | (c) | 0 | | - | - | | | 1 | | | | |
| ARKANSAS | | | | | | | | | | | | | | | |
| COLUMBIA | 26,400 | 1 | 75.0 | 40.0 | | | 1 | 8.0 | | 1 | | | | | |
| LAFAYETTE | 11,000 | 2 | 71.0 | 3.5 (d) | 1 | 8.0 | | | 1 | | | | 1 | | |
| CALIFORNIA | | | | | | | | | | | | | | | |
| FRESNO | 365,900 | 1 | 46.0 | 53.0 | - | - | - | - | 1 | | | | | | |
| KERN | 292,000 | 16 | 833.5 | 368.7 | 3 | 268.0 | - | - | 6 | 3 | 6 | 1 | 1 | | |
| KINGS & FRESNO | - | 1 | 100.0 | 44.0 | - | - | - | - | | | 1 | | | | |
| LOS ANGELES | 6,039,000 | 17 | 409.0 | 225.9 | - | - | - | - | 9 | 2 | 5 | 2 | 1 | | |
| ORANGE | 704,000 | 5 | 140.0 | 73.9 | - | - | - | - | 2 | 1 | 1 | 1 | | | |
| SANTA BARBARA | 169,000 | 7 | 250.0 | 115.0 | - | - | - | - | 1 | 2 | 4 | | | | |
| VENTURA | 199,000 | 6 | 180.0 | 60.6 | - | - | - | - | 2 | 2 | 1 | 1 | | | |
| COLORADO | | | | | | | | | | | | | | | |
| ARAPAHOE | 113,000 | 1 | 8.0 | 7.6 | - | - | - | - | | | 1 | | | | |
| LA PLATTA | 19,000 | 1 | 300.0 | 206.4 | - | - | - | - | 1 | | | | | | |
| LOGAN | 20,000 | 1 | 10.0 | 6.0 | - | - | - | - | | 1 | | | | | |
| MESA | 51,000 | 1 | 20.0 | 14.3 | - | - | - | - | | | | | | | 1 |
| MORGAN | 21,000 | 3 | 39.0 | 16.1 | - | - | - | - | | 1 | 1 | | | | 1 |
| RIO BLANCA | 5,000 | 4 | 60.8(d) | 34.7(d) | - | - | - | - | | 2 | 1 | | | | 1 |

# NATURAL GAS PROCESSING PLANTS IN UNITED STATES ; JANUARY 1, 1972

| STATE COUNTY | COUNTY POP 1980 | TOTAL NUMBER OF PLANTS | TOTAL GAS CAPACITY MM CFD | TOTAL GAS THRU-PUT MM CFD | NUMBER OF GAS RECYCLE PLANTS | RECYCLE PLANTS CAPACITY MM CFD | SULFUR RECOVERY PLANTS NUMBER | SULFUR RECOV-ERED LT/DAY | TYPE OF PROCESS[a] AND NUMBER[a] OF PLANTS USING EACH PPOCESS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | A | B | C | D | E | OTHER | NOT AVAIL. |
| FLORIDA | | | | | | | | | | | | | | | |
| BRADFORD | 12,000 | 1 | 900.0 | 680.0 | - | - | - | - | | 1 | | | | | |
| ILLINOIS | | | | | | | | | | | | | | | |
| DOUGLAS | 19,000 | 1 | 560.0 | 545.0 | - | - | - | - | | 1 | | | | | |
| KANSAS | | | | | | | | | | | | | | | |
| BARBER | 9,000 | 1 | 30.0 | (c) | - | - | - | - | 1 | | | | | | |
| ELLSWORTH | 8,000 | 2 | 1426.0 | 1,360.0 | - | - | - | - | | 1 | | | | H 1 | |
| FINNEY | 16,000 | 1 | 200.0 | 195.0 | - | - | - | - | | | 1 | | | | |
| FORD | 21,000 | 1 | 25.0 | (c) | - | - | - | - | | 1 | | | | | |
| GRANT | 5,000 | 5 | 1325.0 | 1,246.9 | - | - | - | - | 1 | 4 | | | | | |
| HARPER | 10,000 | 1 | 85.0 | 44.0 | - | - | - | - | 1 | | | | | | |
| HARVEY | 26,000 | 1 | 3.0 | 0.9 | - | - | - | - | | | | | | | 1 |
| KEARNEY | 3,000 | 1 | 215.0 | 96.0 | - | - | - | - | 1 | | | | | | |
| KINGMAN | 10,000 | 2 | 125.0 | 126.5 | - | - | - | - | | 2 | | | | | |
| MORTON | 3,000 | 4 | 217.5 | 72.9(d) | - | - | - | - | | 1 | 2 | | 1 | | |
| PRATT | 12,000 | 1 | 12.0 | (c) | - | - | - | - | | 1 | | | | | |
| RENO | 57,000 | 1 | (c) | (c) | - | - | - | - | | | | | | G 1 | |
| RUSH | 6,000 | 1 | 24.0 | 24.0 | - | - | - | - | | 1 | | | | | |
| SCOTT | 5,000 | 1 | 200.0 | 178.0 | - | - | - | - | | 1 | | | | | |
| SEDGEWICK | 343,000 | 1 | 130.0 | 116.0 | - | - | - | - | 1 | | | | | | |
| SEWARD | 16,000 | 4 | 1,350.0 | 1,237.0 | - | - | - | - | 1 | 2 | 1 | | | | |
| STANTON | 2,000 | 1 | 7.0 | 5.1 | - | - | - | - | | | | | | | 1 |
| KENTUCKY | | | | | | | | | | | | | | | |
| FLOYD | 53,000 | 1 | 50.0 | 50.2 | | | | | 1 | | | | | | |
| GREEN | 11,000 | 1 | 925.0 | (c) | | | | | | 1 | | | | | |
| GREENUP | 29,000 | 1 | (c) | (c)(e) | | | | | | | | | | | |

# NATURAL GAS PROCESSING PLANTS IN UNITED STATES; JANUARY 1, 1972

| STATE COUNTY | COUNTY POP. 1960 | TOTAL NUMBER OF PLANTS | TOTAL GAS CAPACITY MM CFD | TOTAL GAS THRU-PUT MM CFD | NUMBER OF GAS RECYCLE PLANTS | RECYCLE PLANTS CAPACITY MM CFD | SULFUR RECOVERY PLANTS NUMBER | SULFUR RECOV-ERED LT/DAY | TYPE OF PROCESS[a] AND NUMBER[a] OF PLANTS USING EACH PROCESS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | A | B | C | D | E | OTHER | NOT AVAIL. |
| LOUISIANA | | | | | | | | | | | | | | | |
| ACADIA | 50,000 | 7 | 626.0 | 438.5 | — | — | — | — | 1 | 5 | 1 | | | | |
| ALLEN | 20,000 | 1 | 24.0 | 12.6 | — | — | — | — | | 1 | | | | | |
| ASCENSION | 28,000 | 2 | (e) | (e) | — | — | — | — | | | | | | G 2 | |
| ASSUMPTION | 18,000 | 3 | 91.0(d) | 24.0(d) | — | — | — | — | | | | | 2 | G 1 | |
| AVOYELLES | 38,000 | 1 | 7.0 | (e) | — | — | — | — | 1 | | | | | | |
| BEAUREGARD | 19,000 | 3 | 21.0 | 17.9 | 3 | 21.0 | — | — | | 2 | 1 | | | | |
| BOSSIER | 57,000 | 5 | 950.0 | 90.1 | 1 | 50.0 | — | — | 1 | 3 | | | 1 | | |
| CADDO | 234,000 | 1 | 25.0 | (e) | — | — | — | — | | | | | | | 1 |
| CALCASIEU | 154,000 | 6 | 593.0(d) | 481.5(d) | — | — | — | — | | 2 | 1 | | 2 | G 1 | |
| CAMERON | 7,000 | 13 | 2,269.5 | 1,675.6(d) | 1 | 14.0 | — | — | 1 | 8 | 2 | | 3 | | |
| CLAIBORNE | 19,000 | 3 | 35.0(d) | 76.7 | 1 | 35.0 | — | — | 1 | 2 | | | | | |
| CONCORDIA | 20,000 | 1 | 7.0 | 3.3 | — | — | — | — | | | 1 | | | | |
| EAST BATON ROUGE | 230,000 | 1 | 8.0 | 5.0 | — | — | — | — | | | 1 | | | | |
| EVANGELINE | 32,000 | 2 | 140.0 | 118.0 | — | — | — | — | | 2 | | | | | |
| IBERIA | 52,000 | 3 | 165.0 | 92.0 | 1 | 129.0 | — | — | | 2 | | | 1 | | |
| IBERVILLE | 30,000 | 1 | 71.0 | 69.0 | — | — | — | — | | 1 | | | | | |
| JEFFERSON | 209,000 | 1 | 100.0 | 76.0 | — | — | — | — | | 1 | | | | | |
| JEFFERSON DAVIS | 30,000 | 4 | 425.0 | 181.0(d) | 2 | 140.0 | — | — | 1 | 3 | | | | | |
| LAFAYETTE | 85,000 | 1 | 32.0 | 33.3 | — | — | — | — | | 1 | | | | | |
| LAFOURCHE | 55,000 | 4 | 211.0 | 135.0 | — | — | — | — | | 2 | | | 2 | | |
| LINCOLN | 29,000 | 3 | 330.0 | 90.0 | — | — | — | — | 2 | 1 | | | | | |
| MOREHOUSE | 34,000 | 1 | 500.0 | 500.0 | — | — | — | — | 1 | | | | | | |
| NATCHITOCHES | 36,000 | 1 | 150.0 | 159.0 | — | — | — | — | | 1 | | | | | |
| OUACHITA | 102,000 | 2 | 144.0 | 91.0 | — | — | — | — | | 1 | | | 1 | | |
| PLAQUEMINES | 23,000 | 7 | 2,620.0 | 1,954.0(d) | — | — | — | — | | 4 | 1 | | 2 | | |
| POINTE COUPEE | 22,000 | 3 | 130.0 | 25.2(d) | 1 | 30.0 | — | — | 1 | 2 | | | | | |
| RICHLAND | 24,000 | 1 | 15.0 | 17.9 | — | — | — | — | | | 1 | | | | |
| ST. BERNARD | 32,000 | 4 | 3,165.0 | 2,904.0 | — | — | — | — | | 3 | | | 1 | | |
| ST. CHARLES | 21,000 | 2 | 800.0(d) | (e) | — | — | — | — | | 1 | | | | G 1 | |

# NATURAL GAS PROCESSING PLANTS IN UNITED STATES, JANUARY 1, 1972

| STATE COUNTY | COUNTY POP. 1960 | TOTAL NUMBER OF PLANTS | TOTAL GAS CAPACITY MM CFD | TOTAL GAS THRU-PUT MM CFD | NUMBER OF GAS RECYCLE PLANTS | RECYCLE PLANTS CAPACITY MM CFD | SULFUR RECOVERY PLANTS NUMBER | SULFUR RECOVERED LT/DAY | TYPE OF PROCESS[a] AND NUMBER[b] OF PLANTS USING EACH PROCESS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | A | B | C | D | E | OTHER | NOT AVAIL. |
| LOUISIANA | | | | | | | | | | | | | | | |
| ST JAMES | 18,000 | 4 | 75.5 | 32.8 | – | – | – | – | | 1 | | | 3 | | |
| ST. LANDRY | 81,000 | 5 | 312.0 | 297.0 | 1 | 100.0 | – | – | | 4 | | | 1 | | |
| ST. MARTIN | 29,000 | 6 | 389.5(d) | 295.0(d) | – | – | – | – | | 2 | 1 | | 2 | G 1 | |
| ST. MARY | 50,000 | 8 | 3,936.0 | 2,678.3(d) | – | – | – | – | | 7 | 1 | | 1 | | |
| TENSAS | 12,000 | 1 | 120.0 | 60.0 | 1 | 120.0 | – | – | 1 | | | | | | |
| TERREBONNE | 61,000 | 14 | 2,615.5 | 3,021.0(d) | – | – | – | – | | 5 | 2 | | 7 | | |
| VERMILION | 39,000 | 6 | 2,200.0 | 1,017.2(d) | – | – | – | – | | 4 | | | 2 | | |
| WEBSTER | 40,000 | 5 | 333.5 | 189.9 | 1 | 220.0 | – | – | 1 | 2 | 1 | | 1 | | |
| NORTH BIG ISLAND FIELD | – | 1 | 1.5 | 0.8 | – | – | – | – | | | 1 | | | | |
| MICHIGAN | | | | | | | | | | | | | | | |
| CRAWFORD | 5,000 | 1 | 1.5 | 1.0 | – | – | – | – | | | | | 1 | | |
| HILLSDALE | 35,000 | 1 | 38.0 | 30.5 | – | – | – | – | | 1 | | | | | |
| OSCEOLA | 14,000 | 1 | 54.0 | 52.0 | – | – | – | – | | 1 | | | | | |
| ST. CLAIR | 107,000 | 1 | 35.0 | 29.0 | – | – | – | – | | 2 | | | | | |
| WASHTENAW | 172,000 | 1 | 600.0 | 600.0 | – | – | – | – | | | | | 5 | | |
| MISSISSIPPI | | | | | | | | | | | | | | | |
| ADAMS | 38,000 | 1 | 4.0 | 0.7 | – | – | – | – | | | 1 | | | | |
| CLARKE | 16,000 | 2 | 40.0 | 26.0 | – | – | 1 | 3 | | | 1 | | | | 1 |
| FORREST | 53,000 | 1 | 60.0 | 11.8 | – | – | – | – | | | | | 1 | | |
| JASPER | 17,000 | 1 | 10.0 | (c) | – | – | – | – | | | 1 | | | | |
| MARION | 23,000 | 2 | 29.0 | 10.5 | – | – | – | – | | 1 | 1 | | | | |
| PIKE | 35,000 | 1 | 20.0 | 7.2 | – | – | – | – | | | | 1 | | | |
| SMITH | 14,000 | 1 | 15.0 | 8.0 | – | – | – | – | | 1 | | | | | |
| MONTANA | | | | | | | | | | | | | | | |
| FALLON | 9,000 | 1 | 5.8 | 5.0 | – | – | – | – | 1 | | | | | | |
| GLACIER | 12,000 | 1 | 30.0 | 20.0 | – | – | – | – | | | | | | | |
| MUSSELSHELL | 5,000 | 1 | 4.0 | 1.0 | – | – | – | – | | | 1 | | | | |

# NATURAL GAS PROCESSING PLANTS IN UNITED STATES, JANUARY 1, 1972

| STATE COUNTY | COUNTY POP. 1980 | TOTAL NUMBER OF PLANTS | TOTAL GAS CAPACITY MM CFD | TOTAL GAS THRU-PUT MM CFD | NUMBER OF GAS RECYCLE PLANTS | RECYCLE PLANTS CAPACITY MMCFD | SULFUR RECOVERY PLANTS NUMBER | SULFUR RECOV-ERED LT/DAY | TYPE OF PROCESS[a] AND NUMBER[b] OF PLANTS USING EACH PROCESS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | A | B | C | D | E | OTHER | NOT AVAIL. |
| MONTANA | | | | | | | | | | | | | | | |
| POWDER RIVER | 2,000 | 1 | 25.0 | 9.5 | - | - | - | - | | 1 | | | | | |
| RICHLAND | 14,000 | 1 | 6.0 | 4.0 | - | - | - | - | | | 1 | | | | |
| ROOSEVELT | 12,000 | 1 | 2.5 | 0.8 | - | - | - | - | | | 1 | | | | |
| NEBRASKA | | | | | | | | | | | | | | | |
| CHEYENNE | 15,000 | 1 | 12.5 | 7.0 | - | - | - | - | | 1 | | | | | |
| KIMBALL | 8,000 | 1 | 12.0 | 6.1 | 1 | 12.0 | - | - | | 1 | | | | | |
| NEW MEXICO | | | | | | | | | | | | | | | |
| EDDY | 51,000 | 5 | 330.0 | 217.7[d] | - | - | 1 | 27 | 1 | 2 | | | 1 | | 1 |
| LEA | 53,000 | 23 | 1,478.5[d] | 1,036.1[d] | 1 | 85.0 | - | - | 9 | 9 | 3 | | 1 | G 1 | |
| MCKINLEY | 37,000 | 1 | (e) | (e) | - | - | - | - | | | | | | G 1 | |
| RIO ARRIBA | 29,000 | 1 | 95.0 | 68.9 | - | - | - | - | | 1 | | | | | |
| ROOSEVELT | 16,000 | 1 | 56.5 | 36.7 | - | - | 1 | 4 | | 1 | | | | | |
| SAN JUAN | 53,000 | 5 | 1,368.0 | 1271.2 | - | - | - | - | 3 | 1 | | | 1 | | |
| NORTH DAKOTA | | | | | | | | | | | | | | | |
| BURKE | 6,000 | 2 | 32.0 | 8.8[d] | - | - | - | - | | 2 | | | | | |
| WILLIAMS | 22,000 | 1 | 105.0 | 76.2 | - | - | 1 | 12.1 | 1 | | | | | | |
| OKLAHOMA | | | | | | | | | | | | | | | |
| ALFALFA | 8,000 | 1 | 45.0 | 33.1 | - | - | - | - | | 1 | | | | | |
| BEAVER | 7,000 | 7 | 310.0 | 269.7 | - | - | - | - | 2 | 2 | 1 | | 1 | | 1 |
| BECKHAM | 18,000 | 1 | 225.0 | 95.0 | 1 | 225.0 | - | - | | 1 | | | | | |
| BLAINE | 12,000 | 2 | 70.0 | 47.5 | - | - | - | - | | 2 | | | | | |
| CADDO | 29,000 | 1 | 7.0 | (e) | - | - | - | - | | | 1 | | | | |
| CANADIAN | 25,000 | 1 | 125.0 | 106.8 | - | - | - | - | | 1 | | | | | |
| CARTER | 39,000 | 2 | 80.0 | 72.4 | - | - | - | - | | 1 | 1 | | | | |
| CIMARRON | 4,000 | 1 | 50.0 | 42.0 | - | - | - | - | | | 1 | | | | |
| CLEVELAND | 48,000 | 2 | 30.0[d] | 17.8[d] | - | - | - | - | | | 1 | | | G 1 | |

# NATURAL GAS PROCESSING PLANTS IN UNITED STATES, JANUARY 1, 1972

| STATE COUNTY | COUNTY POP. 1980 | TOTAL NUMBER OF PLANTS | TOTAL GAS CAPACITY MM CFD | TOTAL GAS THRU-PUT MM CFD | NUMBER OF GAS RECYCLE PLANTS | RECYCLE PLANTS CAPACITY MM CFD | SULFUR RECOVERY PLANTS NUMBER | SULFUR RECOV-ERED L.T./DAY | TYPE OF PROCESS[a] AND NUMBER[b] OF PLANTS USING EACH PROCESS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | A | B | C | D | E | OTHER | NOT AVAIL |
| **OKLAHOMA** | | | | | | | | | | | | | | | |
| CREEK | 48,000 | 2 | 26.0 | 5.5(d) | - | - | - | - | 1 | 1 | | | | | |
| CUSTER | 21,000 | 2 | 58.0 | 50.0 | - | - | - | - | | | | | | | 2 |
| DEWEY | 6,000 | 6 | 195.0 | 152.0 | - | - | - | - | | 3 | 3 | | | | |
| ELLIS | 5,000 | 1 | 50.0 | 10.0 | - | - | - | - | | | | | | | 1 |
| GARFIELD | 53,000 | 5 | 203.0 | 152.9 | - | - | - | - | 1 | 2 | 2 | | | | |
| GARVIN | 28,000 | 4 | 216.0(d) | 190.3(d) | - | - | - | - | 4 | | | | | | |
| GRADY | 32,000 | 2 | 600(d) | 72.0 | - | - | - | - | 1 | 1 | | | | | |
| GRANT | 8,000 | 3 | 50.0 | 39.2 | - | - | - | - | | 3 | | | 1 | | |
| HARPER | 6,000 | 1 | 225.0 | 206.5 | - | - | - | - | | 1 | | | | | |
| HUGHES | 15,000 | 1 | 25.0 | (c) | - | - | - | - | | 1 | | | | | |
| KAY | 51,000 | 4 | 388.7 | 338.7 | - | - | - | - | | 3 | 1 | | | | |
| KINGFISHER | 11,000 | 4 | 248.0 | 201.4 | - | - | - | - | | 3 | | | 1 | | |
| LINCOLN | 19,000 | 3 | 37.0 | 11.3(d) | - | - | - | - | | 1 | 1 | 1 | | | |
| LOGAN | 29,000 | 1 | 35.0 | 14.4 | - | - | - | - | 1 | | | | | | |
| LOVE | 6,000 | 2 | 73.0 | 16.6(d) | - | - | - | - | | 2 | | | | | |
| MAJOR | 8,000 | 3 | 162.0 | 127.3(d) | - | - | - | - | 1 | 1 | 1 | | | | |
| MARSHALL | 7,000 | 1 | 27.0 | 19.7 | - | - | - | - | | 1 | | | | | |
| McLEAN | 13,000 | 4 | 65.0 | 54.4 | - | - | - | - | | 3 | 1 | | | | |
| NOBLE | 10,000 | 1 | 3.0 | 2.0 | - | - | - | - | | | 1 | | | | |
| OKFUSKEE | 13,000 | 1 | 1.0 | 0.6 | - | - | - | - | | | | 1 | | | |
| OKLAHOMA | 440,000 | 4 | 186.0 | 11.5(d) | - | - | - | - | 2 | 1 | 1 | | | | |
| POTTOTOC | 28,000 | 2 | 6.5 | 5.6 | - | - | - | - | | | 2 | | | | |
| SEMINOLE | 28,000 | 3 | 60.0 | 15.5 | - | - | - | - | 3 | | | | | | |
| STEPHENS | 38,000 | 5 | 177.0(d) | 61.6(d) | - | - | - | - | 1 | 4 | | | | | |
| TEXAS | 14,000 | 6 | 369.0 | 315.4 | - | - | - | - | 2 | 4 | | | | | |
| WOODWARD | 14,000 | 3 | 321.0 | 147.5(d) | - | - | - | - | 1 | 1 | 1 | | | | |
| **PENNSYLVANIA** | | | | | | | | | | | | | | | |
| ELK | 37,000 | 1 | 4.0 | 2.5 | - | - | - | - | 1 | | | | | | |
| VENANGO | 65,000 | 1 | 4.0 | 0.8 | - | - | - | - | 1 | | | | | | |

# NATURAL GAS PROCESSING PLANTS IN UNITED STATES, JANUARY 1, 1972

| STATE COUNTY | COUNTY POP 1960 | TOTAL NUMBER OF PLANTS | TOTAL GAS CAPACITY MM CFD | TOTAL GAS THRU-PUT MM CFD | NUMBER OF GAS RECYCLE PLANTS | RECYCLE PLANTS CAPACITY MM CFD | SULFUR RECOVERY PLANTS NUMBER | SULFUR RECOVERED L.T./DAY | TYPE OF PROCESS[a] AND NUMBER[b] OF PLANTS USING EACH PROCESS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | A | B | C | D | E | OTHER | NOT AVAIL. |
| SOUTH DAKOTA | | | | | | | | | | | | | | | |
| BUTTE | 9,000 | 1 | 38.0 | 30.0 | - | - | - | - | | 1 | | | | | |
| TEXAS | | | | | | | | | | | | | | | |
| ANDERSON | 28,000 | 1 | 15.0 | 6.0 | - | - | - | - | | 1 | | | | | |
| ANDREWS | 13,000 | 8 | 422.0 | 176.2 | - | - | 1 | 8.0 | 3 | 4 | | | 1 | | |
| ARANSAS | 7,000 | 1 | 75.0 | 64.0 | - | - | - | - | | 1 | | | | | |
| ATACOSA | 19,000 | 4 | 156.0(d) | 160.1 | - | - | 2 | 45.6 | 2 | | | | 2 | | |
| BEE | 24,000 | 3 | 207.0 | 139.0 | 1 | 130.0 | - | - | 1 | 1 | | | | | 1 |
| BEXAR | 687,000 | 1 | 150.0 | 105.0 | - | - | - | - | | | | | | 1 | |
| BRAZORIA | 76,000 | 10 | 2,509.7 | 1,661.9 | - | - | 1 | 26.0 | 1 | 6 | | | 3 | | |
| BROOKS | 9,000 | 7 | 714.0 | 558.9 | 3 | 627.0 | - | - | 2 | 3 | | | 2 | | |
| CALHOUN | 17,000 | 4 | 273.0 | 173.2 | 1 | 97.1 | - | - | | 3 | | | 1 | | |
| CALLAHAN | 8,000 | 1 | 5.0 | 3.0 | - | - | - | - | | | 1 | | | | |
| CARSON | 8,000 | 1 | 10.0 | 7.0 | - | - | - | - | | | 1 | | | | |
| CASS | 23,000 | 2 | 85.0 | 55.0 | 1 | 70.0 | 1 | 18.5 | 2 | | | | | | |
| CHAMBERS | 10,000 | 4 | 277.0(d) | 240.7(d) | 1 | 225.0 | - | - | | 1 | 1 | | 1 | 1 | |
| CHEROKEE | 33,000 | 1 | 30.0 | 15.1 | - | - | - | - | | 1 | | | | | |
| COCHRAN | 6,000 | 1 | 25.0 | 20.0 | - | - | 1 | 4 | | 1 | | | | | |
| COKE | 4,000 | 3 | 136.0 | 96.2 | - | - | - | - | 1 | 2 | | | | | |
| COLORADO | 18,000 | 4 | 595.0 | 391.7 | - | - | - | - | | 3 | 1 | | | | |
| COMANCHE | 13,000 | 1 | 5.0 | 0.7 | - | - | - | - | | | 1 | | | | |
| CONCHO | 4,000 | 1 | 14.0 | 10.7 | - | - | - | - | | 1 | | | | | |
| COOKE | 23,000 | 2 | 33.0 | 21.6 | - | - | - | - | 1 | 1 | | | | | |
| CRANE | 5,000 | 6 | 268.0(d) | 459.0(d) | 1 | 63.0 | 2 | 125.5 | 3 | 3 | | | | | |
| CROCKETT | 4,000 | 6 | 183.0 | 155.8 | 1 | 20.0 | - | - | | 2 | 3 | | | | 1 |
| DAWSON | 19,000 | 2 | 8.0 | 1.9(d) | - | - | - | - | | | 2 | | | | |
| DEWITT | 21,000 | 1 | 150.0 | 130.0 | - | - | - | - | | 1 | | | | | |
| DIMMITT | 10,000 | 1 | 15.0 | 18.0 | - | - | - | - | | | | | | | 1 |
| DUVAL | 13,000 | 2 | 105.0 | 62.6 | - | - | - | - | 1 | 1 | | | | | |
| EASTLAND | 20,000 | 4 | 23.3 | 18.6 | - | - | - | - | | 1 | 2 | 1 | | | |
| ECTOR | 91,000 | 8 | 811.0 | 319.2(d) | 1 | 160.0 | 2 | 36.3 | 1 | 1 | | | | | |

# NATURAL GAS PROCESSING PLANTS IN UNITED STATES, JANUARY 1, 1972

| STATE COUNTY | COUNTY POP. 1960 | TOTAL NUMBER OF PLANTS | TOTAL GAS CAPACITY MM CFD | TOTAL GAS THRU-PUT MM CFD | NUMBER OF GAS RECYCLE PLANTS | RECYCLE PLANTS CAPACITY MM CFD | SULFUR RECOVERY PLANTS NUMBER | SULFUR RECOV-ERED L.T./DAY | TYPE OF PROCESS[a] AND NUMBER[b] OF PLANTS USING EACH PROCESS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | A | B | C | D | E | OTHER | NOT AVAIL |
| TEXAS | | | | | | | | | | | | | | | |
| ERATH | 16,000 | 1 | 25.0 | 6.0 | — | — | — | — | | 1 | | | | | |
| FISHER | 8,000 | 2 | 30.0 | 29.6 | — | — | — | — | | | 2 | | | | |
| FORT BEND | 41,000 | 3 | 132.0 | 108.6 | — | — | — | — | | 1 | | | 2 | | |
| FRANKLIN | 5,000 | 1 | 50.0 | 41.0 | 1 | 58.0 | — | — | 1 | | | | | | |
| FRIO | 10,000 | 1 | 20.0 | 9.0 | — | — | — | — | | 1 | | | | | |
| GAINES | 12,000 | 3 | 113.0 | 52.5 | 1 | 38.0 | 1 | 23.0 | | 2 | 1 | | | | |
| GALVESTON | 140,000 | 4 | 93.0 | 53.7 | 1 | 30.0 | — | — | | 2 | 1 | | 1 | | |
| GRAY | 32,000 | 6 | 295.0 | 62.9[d] | 1 | 50.0 | — | — | 2 | 4 | | | | | |
| GRAYSON | 73,000 | 3 | 75.0 | 42.5[d] | 1 | 25.0 | — | — | | 1 | 1 | | 1 | | |
| GREGG | 69,000 | 5 | 70.0[d] | 61.1 | — | — | — | — | 2 | 2 | | | | | 1 |
| HALE | 37,000 | 1 | 16.0 | 16.0 | — | — | — | — | | | 1 | | | | |
| HANSFORD | 6,000 | 2 | 510 | (c) | — | — | — | — | 1 | 1 | | | | | |
| HARDEMAN | 8,000 | 1 | 15.0 | 6.0 | — | — | — | — | | | 1 | | | | |
| HARDIN | 25,000 | 3 | 139.0 | 81.2 | — | — | — | — | 1 | 1 | | | 1 | | |
| HARRIS | 1,243,000 | 5 | 380.0[d] | 333.7[d] | — | — | — | — | | 2 | | | | G 2 | 1 |
| HARRISON | 46,000 | 4 | 360.0 | 116.6 | — | — | — | — | 1 | 1 | | | 1 | | 1 |
| HENDERSON | 22,000 | 3 | 235.0 | 70.4 | — | — | — | — | 2 | 1 | | | | | |
| HIDALGO | 181,000 | 11 | 639.0 | 311.3 | — | — | — | — | 1 | 5 | 1 | | 4 | | |
| HOCKLEY | 22,000 | 3 | 122.0 | 99.7 | — | — | 1 | 36.0 | 2 | | 1 | 1 | | | |
| HOPKINS | 19,000 | 1 | (c) | 13.0 | — | — | 1 | 41 | 1 | | | | | | |
| HOUSTON | 19,000 | 1 | 40.0 | 30.0 | — | — | — | — | | 1 | | | | | |
| HOWARD | 40,000 | 1 | 55.0 | (c) | — | — | — | — | | 1 | | | | | |
| HUTCHINSON | 34,000 | 9 | 1,093.0 | 370.0[d] | 1 | 2940 | — | — | 5 | 3 | | | 1 | | |
| IRION | 1,000 | 2 | 30.6 | 26.5 | 1 | 2.6 | — | — | | 1 | 2 | | | | |
| JACK | 7,000 | 3 | 19.0 | 14.6 | — | — | — | — | | 1 | 1 | 1 | | | |
| JACKSON | 14,000 | 5 | 360.0[d] | 209.7[d] | 1 | 57.0 | — | — | | 3 | | | 1 | | 1 |
| JEFFERSON | 246,000 | 7 | 535.0[d] | 233.8 | 1 | 57.0 | — | — | | 5 | | | 2 | | |
| JIM HOGG | 5,000 | 2 | 108.0 | 74.7 | — | — | — | — | | | 1 | | 1 | | |
| JIM WELLS | 35,000 | 5 | 826.0 | 710.8[d] | 2 | 393.0 | — | — | | 3 | 2 | | | | |
| KARNES | 15,000 | 1 | 60.0 | 49.0 | — | — | — | — | | 1 | | | | | |
| KENEDY | 1,000 | 1 | 210.0 | 202.6 | 1 | 210.0 | — | — | | 1 | | | | | |

# NATURAL GAS PROCESSING PLANTS IN UNITED STATES, JANUARY 1, 1972

| STATE COUNTY | COUNTY POP 1960 | TOTAL NUMBER OF PLANTS | TOTAL GAS CAPACITY MM CFD | TOTAL GAS THRU PUT MM CFD | NUMBER OF GAS RECYCLE PLANTS | RECYCLE PLANTS CAPACITY MM CFD | SULFUR RECOVERY PLANTS NUMBER | SULFUR RECOVERED L.T./DAY | TYPE OF PROCESS[a] AND NUMBER[b] OF PLANTS USING EACH PROCESS A | B | C | D | E | OTHER | NOT AVAIL. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TEXAS | | | | | | | | | | | | | | | |
| KENT | 2,000 | 1 | 16.0 | 12.6 | – | – | – | – | | | | 1 | | | |
| KLEBERG | 30,000 | 2 | 1,759.0 | 1,760.5 | 1 | 1,725.0 | | | 1 | 1 | | | | | |
| LAVACA | 20,000 | 3 | 275.0 | 132.5 | 1 | 10.0 | – | – | | 1 | | | 2 | | |
| LEON | 10,000 | 1 | 10.0 | 1.7 | – | – | – | – | | | | | 1 | | |
| LIBERTY | 32,000 | 4 | 152.0 | 76.2 | – | – | – | – | | 2 | 1 | | 1 | | |
| LIVE OAK | 8,000 | 5 | 267.0 | 137.2 | 1 | 95.0 | – | – | 3 | 1 | | | 1 | | |
| McCLENNAN | 150,000 | 1 | 60.0 | 46.9 | – | – | – | – | | | 1 | | | | |
| McMULLEN | 1,000 | 2 | 97.0 | 26.0 | – | – | – | – | | | | | 2 | | |
| MADISON | 7,000 | 1 | 20.0 | 19.7 | – | – | – | – | | | | | 1 | | |
| MARION | 8,000 | 1 | 3.2 | 2.5 | – | – | – | – | | | | | 1 | | |
| MARTIN | 5,000 | 2 | 23.0 | 19.0 | – | – | – | – | | | 2 | | | | |
| MATAGORDA | 26,000 | 9 | 1,001.0 | 462.7(d) | 1 | 30.0 | – | – | | 6 | | | 3 | | |
| MAVERICK | 15,000 | 1 | 5.0 | 2.2 | – | – | – | – | | | 1 | | | | |
| MIDLAND | 68,000 | 7 | 187.0(d) | 183.4(d) | 3 | 105(d) | – | – | 3 | 2 | 2 | | | | |
| MONTAGUE | 15,000 | 1 | 25.0 | 6.8 | – | – | – | – | | 1 | | | | | |
| MONTGOMERY | 27,000 | 5 | 160.0 | 105.6 | – | – | – | – | 3 | 2 | | | | | |
| MOORE | 15,000 | 7 | 1,590.0 | 666.0 | – | – | – | – | 4 | 2 | | | 1 | | |
| NAVARRO | 34,000 | 1 | 12.0 | 11.0 | – | – | 1 | 7 | | | | | | | 1 |
| NOLAN | 19,000 | 3 | 36.0 | 29.9 | – | – | – | – | 1 | | 2 | 1 | | | |
| NUECES | 223,000 | 10 | 938.0 | 776.6 | – | – | – | – | 2 | 5 | | | 1 | | 2 |
| OCHILTREE | 9,000 | 2 | 250.0 | 120.0(d) | – | – | – | – | | 1 | 1 | | | | |
| PALO PINTO | 21,000 | 3 | 120.0 | 85.0 | – | – | – | – | | 1 | | | 2 | | |
| PANOLA | 17,000 | 6 | 670.0(d) | 333.6(d) | – | – | – | – | 1 | 3 | | | | 61 | 1 |
| PARKER | 23,000 | 2 | 135.0 | 106.7 | – | – | – | – | 1 | 1 | | | | | |
| PECOS | 12,000 | 9 | 1,022.0(d) | 684.3(d) | 2 | 560.0 | – | – | 2 | 4 | 1 | | 1 | | 1 |
| POTTER | 116,000 | 2 | 230.0 | 129.1 | – | – | – | – | | 2 | | | | | |
| REAGAN | 4,000 | 3 | 198.0 | 106.6 | – | – | – | – | 1 | | 1 | | | | 1 |
| REEVES | 18,000 | 2 | 38.0 | 5.8(d) | – | – | – | – | 1 | | 1 | | | | |
| REFUGIO | 11,000 | 5 | 386.5 | 179.1 | – | – | – | – | 1 | 1 | 3 | | 1 | | |
| RUNNELS | 15,000 | 1 | 1.1 | 0.2 | – | – | – | – | | | 1 | | | | |

# NATURAL GAS PROCESSING PLANTS IN UNITED STATES; JANUARY 1, 1972

| STATE COUNTY | COUNTY POP. 1960 | TOTAL NUMBER OF PLANTS | TOTAL GAS CAPACITY MM CFD | TOTAL GAS THRU-PUT MM CFD | NUMBER OF GAS RECYCLE PLANTS | RECYCLE PLANTS CAPACITY MM CFD | SULFUR RECOVERY PLANTS NUMBER | SULFUR RECOVERED LT/DAY | TYPE OF PROCESS[a] AND NUMBER[b] OF PLANTS USING EACH PROCESS A | B | C | D | E | OTHER | NOT AVAIL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TEXAS | | | | | | | | | | | | | | | |
| RUSK | 36,000 | 4 | 58.5 | 21.3 d | – | – | – | – | 3 | 1 | | 1 | | | |
| SAN PATRICIO | 45,000 | 8 | 457.5 d | 247.7 | – | – | – | – | 1 | 6 | | | 1 | | |
| SCHLEICHER | 3,000 | 1 | 56.0 | 50.9 | 1 | 56.0 | – | – | 1 | | | | | | |
| SCURRY | 20,000 | 4 | 303.0 | 170.6 d | – | – | – | – | 1 | 1 | 2 | | | | |
| SHACKLEFORD | 4,000 | 2 | 25.0 | 17.0 | – | – | – | – | 1 | | 1 | | | | |
| SMITH | 86,000 | 2 | 13.0 | 4.6 | – | – | – | – | | | 1 | | | | 1 |
| STARR | 17,000 | 7 | 252.0 | 246.0 | – | – | – | – | | 6 | | | 1 | | |
| STEPHENS | 9,000 | 6 | 38.0 d | 24.2 d | – | – | – | – | 2 | 1 | 3 | | | | |
| STONEWALL | 3,000 | 1 | 16.0 | 9.8 | – | – | – | – | | 1 | | | | | |
| TAYLOR | 101,000 | 1 | 8.0 | 2.5 | – | – | – | – | | | 1 | | | | |
| TERRY | 16,000 | 1 | 5.0 | 4.7 | – | – | – | – | | | 1 | 1 | | | |
| TOM GREEN | 65,000 | 2 | 7.0 | 3.9 | – | – | – | – | | | 2 | | | | |
| UPTON | 6,000 | 6 | 167.0 d | 66.0 d | 1 | 12.0 | – | – | 1 | | 2 | 1 | 1 | | |
| VAN ZANDT | 19,000 | 3 | 105.0 | 57.1 | – | – | 2 | 514.0 | | 3 | | | | | |
| VICTORIA | 46,000 | 3 | 149.0 | 89.5 | – | – | – | – | | 2 | 1 | | | | |
| WALLER | 12,000 | 1 | 1,260.0 | 1,076.0 | – | 1,260 | – | – | | 1 | | | | | |
| WARD | 15,000 | 4 | 84.5 d | 60.6 d | – | – | – | – | 1 | 2 | | 1 | | | |
| WEBB | 65,000 | 1 | 190.0 | 130.0 | – | – | – | – | | 1 | | | | | |
| WHARTON | 38,000 | 2 | 130.0 | 67.5 | – | – | – | – | 1 | | | | | | |
| WHEELER | 8,000 | 2 | 16.0 d | 21.0 | – | – | – | – | | 1 | | | | | 1 |
| WILBARGER | 18,000 | 1 | 1.9 | 0.7 | – | – | – | – | | | 1 | | | | |
| WILLACY | 20,000 | 2 | 119.0 | 49.9 | – | – | – | – | | | 1 | | 1 | | |
| WINKLER | 14,000 | 7 | 300.5 d | 236.9 d | 1 | 42.0 | – | – | 1 | 5 | 1 | 1 | | | |
| NISE | 17,000 | 2 | 75.0 d | 239.9 | – | – | – | – | 1 | 1 | | | | | |
| WOOD | 18,000 | 5 | 210.0 d | 101.2 d | 1 | 30.0 | 1 | 26.0 | 1 | 1 | 1 | 1 | 1 | | 1 |
| YOAKUM | 8,000 | 2 | 237.0 | 226.5 | – | – | – | – | 1 | 1 | | | | | |
| YOUNG | 17,000 | 3 | 23.0 | 15.6 | – | – | – | – | 1 | | 2 | | | | |
| ? (WEST PANHANDLE FIELD) | – | 1 | 90.0 | 45.0 | – | – | – | – | | 1 | | 1 | | | |

# NATURAL GAS PROCESSING PLANTS IN UNITED STATES, JANUARY 1, 1972

| STATE / COUNTY | COUNTY POP 1960 | TOTAL NUMBER OF PLANTS | TOTAL GAS CAPACITY MM CFD | TOTAL GAS THRU-PUT MM CFD | NUMBER OF GAS RECYCLE PLANTS | RECYCLE PLANTS CAPACITY M M CFD | SULFUR RECOVERY PLANTS NUMBER | SULFUR RECOVERED LT/DAY | TYPE OF PROCESS [a] AND NUMBER [b] OF PLANTS USING EACH PROCESS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | A | B | C | D | E | OTHER | NOT AVAIL. |
| UTAH | | | | | | | | | | | | | | | |
| SAN JUAN | 9,000 | 2 | 180.0 | 103.8 | - | - | - | - | 1 | 1 | | | | | |
| UINTAH | 12,000 | 1 | 38.0 | 17.6 | - | - | - | - | | | 1 | | | | |
| WEST VIRGINIA | | | | | | | | | | | | | | | |
| KANAWHA | 263,000 | 1 | 35.0 | 29.0 | - | - | - | - | | 1 | | | | | |
| WAYNE | 39,000 | 1 | 170.0 | 104.0 | - | - | - | - | | 1 | | | | | |
| WETZEL | 19,000 | 1 | 80.0 | 82.5 | - | - | - | - | | | 1 | | | | |
| WYOMING | | | | | | | | | | | | | | | |
| CAMPBELL | 6,000 | 9 | 151.6 | 129.8 | - | - | - | - | | 1 | 7 | | | | 1 |
| CARBON | 15,000 | 2 | 222.5 | 195.1 | - | - | - | - | | 2 | | | | | |
| CONVERSE | 6,000 | 2 | 108.0 | 25.4 | - | - | - | - | | 1 | 1 | | | | |
| CROOK | 5,000 | 2 | 17.0 | 9.0 | - | - | - | - | | 1 | 1 | | | | |
| FREMONT | 26,000 | 2 | 99.6 | 77.9 | - | - | 1 | 40.0 | | 1 | 1 | | | | |
| JOHNSON | 5,000 | 1 | 15.0 | 4.7 | - | - | - | - | | | 1 | | | | |
| LINCOLN | 9,000 | 1 | 250.0 | 190.6 | - | - | - | - | | 1 | | | | | |
| NATRONA | 50,000 | 1 | 80.0 | 60.0 | - | - | - | - | | 1 | | | | | |
| PARK | 17,000 | 2 | 22.7 | 18.7 | - | - | 2 | 69.0 | 1 | 1 | | | | | |
| SUBLETTE | 4,000 | 1 | 20.0 | 12.4 | - | - | - | - | | | | | 1 | | |
| SWEETWATER | 18,000 | 2 | 90.0 | 36.5 | 2 | 90.0 | - | - | | 2 | | | | | |
| UINTA | 7,000 | 1 | 100.0 | 28.5 | - | - | - | - | 1 | | | | | | |
| WASHAKIE | 9,000 | 1 | 50.0 | 31.5 | - | - | - | - | 1 | | | | | | |
| U.S. TOTAL | - | 805 | - | - | 58 | - | 29 | 1,293.4 | 169 | 448 | 130 | 22 | 98 | 15 | 29 |

## NOTES FOR NATURAL GAS PROCESSING PLANTS

**Notes:**

(a) Processes

A. Absorption.

B. Refrigerated Absorption.

C. Refrigeration.

D. Compression.

E. Adsorption.

F. Sulfur Recovery (Process Unknown).

G. Fractionation.

H. Cryogenic.

J. Turboexpander

(b) Some plants use more than one process; therefore, the number of plants may be less than the total number of processes.

(c) Not available.

(d) The rate was not reported for one or more plants. The amount shown is total for those plants reported.

(e) Feed stream is from another natural gas plant.

(f) Reference: 3.

# APPENDIX B - METHODS FOR SAMPLING AND ANALYSIS OF WASTE GASES FROM PETROLEUM PROCESSES

# APPENDIX B

## LIST OF METHODS FOR SAMPLING AND ANALYSIS OF WASTE GASES FROM PETROLEUM PROCESSES

1. Hydrocarbon Evaporation Losses from Oil and Water Separation Processes - API Method 754-60. (Reference 56).

   This analysis measures total hydrocarbon loss, and does not identify specific compounds. There are no interferences. Two methods are described:

   a. Method A, "Gravity Difference Method" has a precision of ± 10 percent of mean.

   b. Method B, "ASTM (Engler) Distillation Method." Precision is not reported.

2. Hydrocarbons in the Atmosphere. "Mass Spectrometer Freeze-out Method, API Method 766-58." (Reference 56).

   Determines hydrocarbons from $C_2$ through $C_{10}$ in a sample from the atmosphere when the concentration is 0.1 ppm to 100 ppm. Nitrous oxides interfere. Precision: For a sample containing 34.5 ppm of $C_3$, $C_4$ and $C_5$ hydrocarbons, the standard deviation was 5 75 ppm with a spread of 17.5 ppm.

3. Nitrogen Oxides in Gaseous Combustion Products. "Phenoldisulfonic Acid Method, API Method 770-59." (Reference 56).

   Two methods are given.

   a. "Peroxide Method," for $NO_2$ from 5 ppm to several thousand ppm. Organic nitrates, nitrites and organic nitrogen compounds interfere. $SO_2$ may interfere. Accuracy is ± 3 percent up to 500 ppm, greater than ± 3 percent above 500 ppm.

   b. "Permanganate Method," for $NO_2$ 20 ppm to several thousand ppm. Precision and accuracy ± 10 percent in range, 20 ppm to 1200 ppm nitrogen oxides.

4. Hydrogen Sulfide.

   a. "Tutweiler Apparatus Method, API Method 771-54." (Reference 56). Determines $H_2S$ concentration from 0.05 percent to 10 percent by volume. Mercaptans interfere. Precision is 0.2 ml of titrant. (Note: About 9 ml of titrant is used for each percent $H_2S$ in sample).

   b. "Ammoniacal Cadmium Chloride Method, API Method 772-54." (Reference 56.) Concentration range and interferences are not given. Precision, $\pm$ 10 percent of mean.

5. Hydrogen Sulfide and Mercaptans. "Electrometric Titration Method, API Method 773-54." (Reference 56).

   Any radical (e.g., bromine, iodine, or cyanide) which in alkaline solutions, precipitates a silver salt less soluble than silver mercaptide will interfere with test, as will substances capable of reducing silver ion to metallic silver in alkaline solutions. Precision: Duplicate results by the same operator should not differ by more than 1 percent of mean.

6. Total Sulfur Oxides. "Acidimetric Method, API Method 774-54." (Reference 56).

   Acid gases, such as hydrogen chloride, interfere. Precision: Repeatability, 2 percent of mean.

7. Sulfur Dioxide and Sulfur Trioxide. "Acidimetric Method, API Method 775-54." (Reference 56).

   Acid gases, such as hydrogen chloride, interfere. Precision: Repeatability 2 percent of mean.

8. Sulfur Dioxide in the Atmosphere. "Disulfitomecurate Method, API Method 776-59." (Reference 56).

   Nitrogen dioxide interferes at concentrations greater than 2 ppm unless special procedure, described, is followed. Precision: $\pm$ 10 percent of mean. Accuracy $\pm$ 10 percent of true value.

9. Hydrocarbons.

   "Flame Ionization Method." Reported in Appendix E of Federal Register Vol. 36, No. 21, Saturday, January 30, 1971, Pages 1512-1513.

## APPENDIX C - CRUDE OIL PRODUCTION IN UNITED STATES

PR 109

Job E. P. A.
Location DURHAM, N.C.
Subject

PROCESSES RESEARCH, INC.
INDUSTRIAL PLANNING AND RESEARCH
CINCINNATI NEW YORK

File No 03410 Sheet No C-1
Checked by Date
Computed by G.N.T. Date 11-21-1972

# CRUDE PETROLEUM PRODUCED IN UNITED STATES

## QUANTITY: THOUSAND BARRELS FOR YEAR

| STATE | 1966[a] | 1967[b] | 1968[b] | 1969[c] | 1970[c] | 1975 ESTIMATE |
|---|---|---|---|---|---|---|
| ALABAMA | 8,030 | 7,348 | 7,635 | 7,701 | 7,263 | 6,400 |
| ALASKA | 14,358 | 29,126 | 66,204 | 73,953 | 83,616 | 100,000 |
| ARIZONA | 132 | 2,924 | 3,370 | 2,433 | 1,784 | 1,000 |
| ARKANSAS | 23,824 | 21,075 | 19,464 | 18,049 | 18,035 | 13,000 |
| CALIFORNIA | 345,295 | 359,219 | 375,496 | 375,291 | 372,191 | 365,000 |
| COLORADO | 33,492 | 33,905 | 31,937 | 28,294 | 24,723 | 16,000 |
| FLORIDA | 1,799 | 1,568 | 1,474 | 1,731 | 2,999 | 4,000 |
| ILLINOIS | 61,661 | 59,142 | 56,391 | 50,724 | 43,747 | 25,000 |
| INDIANA | 10,617 | 10,081 | 8,692 | 7,841 | 7,487 | 6,000 |
| KANSAS | 103,738 | 99,200 | 94,505 | 88,716 | 84,853 | 65,000 |
| KENTUCKY | 18,066 | 15,535 | 14,036 | 12,924 | 11,575 | 8,000 |
| LOUISIANA | 674,318 | 774,527 | 817,426 | 844,603 | 906,907 | 1,000,000 |
| MICHIGAN | 14,273 | 13,664 | 12,974 | 12,213 | 11,693 | 10,000 |
| MISSISSIPPI | 55,227 | 57,147 | 58,708 | 64,283 | 65,119 | 75,000 |
| MISSOURI | 97 | 75 | 65 | 67 | 66 | 65 |
| MONTANA | 35,380 | 34,959 | 48,460 | 43,954 | 37,879 | 30,000 |
| NEBRASKA | 13,850 | 13,373 | 13,183 | 12,106 | 11,451 | 10,000 |
| NEVADA | 307 | 279 | 271 | 223 | 149 | 100 |
| NEW MEXICO | 124,154 | 126,144 | 128,550 | 129,227 | 128,184 | 125,000 |
| NEW YORK | 1,735 | 1,972 | 1,532 | 1,256 | 1,194 | 700 |
| NORTH DAKOTA | 27,126 | 25,315 | 25,040 | 22,703 | 21,908 | 16,000 |
| OHIO | 10,899 | 9,924 | 11,204 | 10,972 | 9,864 | 7,500 |
| OKLAHOMA | 224,839 | 230,749 | 223,623 | 224,729 | 223,574 | 223,000 |
| PENNSYLVANIA | 4,337 | 4,387 | 4,160 | 4,448 | 4,093 | 4,000 |

PR 109

Job E.P.A.
Location DURHAM, N.C.
Subject

PROCESSES RESEARCH, INC.
INDUSTRIAL PLANNING AND RESEARCH
CINCINNATI NEW YORK

File No 03410 Sheet No C-2
Checked by Date
Computed by G.N.T Date 11-21-1972

# CRUDE PETROLEUM PRODUCED IN UNITED STATES

## QUANTITY: THOUSAND BARRELS FOR YEAR

| STATE | 1966[a] | 1967[b] | 1968[b] | 1969[c] | 1970[c] | 1975[d] ESTIMATE |
|---|---|---|---|---|---|---|
| SOUTH DAKOTA | 239 | 211 | 187 | 158 | 160 | 100 |
| TENNESSEE | 7 | 7 | 6 | 32 | 309 | 300 |
| TEXAS | 1,057,706 | 1,119,962 | 1,133,380 | 1,151,775 | 1,249,697 | 1,300,000 |
| UTAH | 24,112 | 24,048 | 23,504 | 23,295 | 23,370 | 23,000 |
| VIRGINIA | 1 | 3 | 3 | 1 | 1 | 1 |
| WEST VIRGINIA | 3,674 | 3,561 | 3,312 | 3,104 | 3,124 | 2,500 |
| WYOMING | 134,470 | 136,312 | 144,250 | 154,945 | 160,345 | 155,000 |
| U.S. TOTAL | 3,027,763 | 3,215,742 | 3,329,042 | 3,371,751 | 3,517,450 | 3,492,000 |

NOTES:
a: TABLE 3, PAGE 6, REFERENCE 39
b: TABLE 3, PAGE 7, REFERENCE 33
c: TABLE 3, PAGE 7, REFERENCE 28
d: ESTIMATES BASED ON TREND OF DATA

# APPENDIX D - MARKETED PRODUCTION OF NATURAL GAS IN UNITED STATES

Job E.P.A.
Location DURHAM, N.C.
Subject

PROCESSES RESEARCH, INC.
INDUSTRIAL PLANNING AND RESEARCH
CINCINNATI NEW YORK

File No 03410 Sheet No D-1
Checked by Date
Computed by G.N.T. Date 11-20
1972

## MARKETED PRODUCTION OF NATURAL GAS IN UNITED STATES

MILLION CUBIC FEET PER DAY

| STATE | 1966[a] | 1967[a] | 1968[a] | 1969[a] | 1970[a] | 1975[b] ESTIMATE |
|---|---|---|---|---|---|---|
| ALASKA | 29 | 40 | 47 | 139 | 306 | 1,000 |
| ARKANSAS | 296 | 319 | 428 | 464 | 497 | 500 |
| CALIFORNIA | 1,965 | 1,866 | 1,953 | 1,857 | 1,778 | 1,500 |
| COLORADO | 326 | 320 | 332 | 325 | 290 | 250 |
| ILLINOIS | 17 | 14 | 12 | 10 | 13 | 10 |
| KANSAS | 2,322 | 2,389 | 2,283 | 2,420 | 2,466 | 2,500 |
| KENTUCKY | 196 | 244 | 243 | 223 | 213 | 210 |
| LOUISIANA | 13,967 | 15,664 | 17,530 | 19,802 | 21,338 | 25,000 |
| MICHIGAN | 105 | 92 | 111 | 99 | 106 | 105 |
| MISSISSIPPI | 381 | 382 | 369 | 360 | 345 | 310 |
| MONTANA | 99 | 71 | 53 | 113 | 117 | 120 |
| NEBRASKA | 27 | 23 | 22 | 19 | 16 | 8 |
| NEW MEXICO | 2,770 | 2,925 | 3,181 | 3,118 | 3,121 | 3,120 |
| NEW YORK | 6 | 11 | 13 | 13 | 9 | 10 |
| NORTH DAKOTA | 112 | 109 | 112 | 92 | 96 | 90 |
| OHIO | 118 | 113 | 117 | 136 | 143 | 140 |
| OKLAHOMA | 3,318 | 3,871 | 3,800 | 4,175 | 4,370 | 5,000 |
| PENNSYLVANIA | 216 | 246 | 240 | 217 | 211 | 170 |
| TEXAS | 19,165 | 19,697 | 20,478 | 21,516 | 22,898 | 23,000 |
| UTAH | 144 | 134 | 126 | 128 | 117 | 90 |
| VIRGINIA | 8 | 10 | 9 | 8 | 8 | 7 |
| WEST VIRGINIA | 585 | 579 | 647 | 635 | 664 | 660 |
| WYOMING | 715 | 658 | 679 | 832 | 927 | 950 |
| OTHERS | 8 | 7 | 6 | 5 | 8 | 8 |
| TOTALS | 46,895 | 49,784 | 52,792 | 56,708 | 60,057 | 68,745 |

a. REFERENCE, 55 PAGE 88
b. ESTIMATE BASED ON TREND OF DATA EXCEPT ALASKA

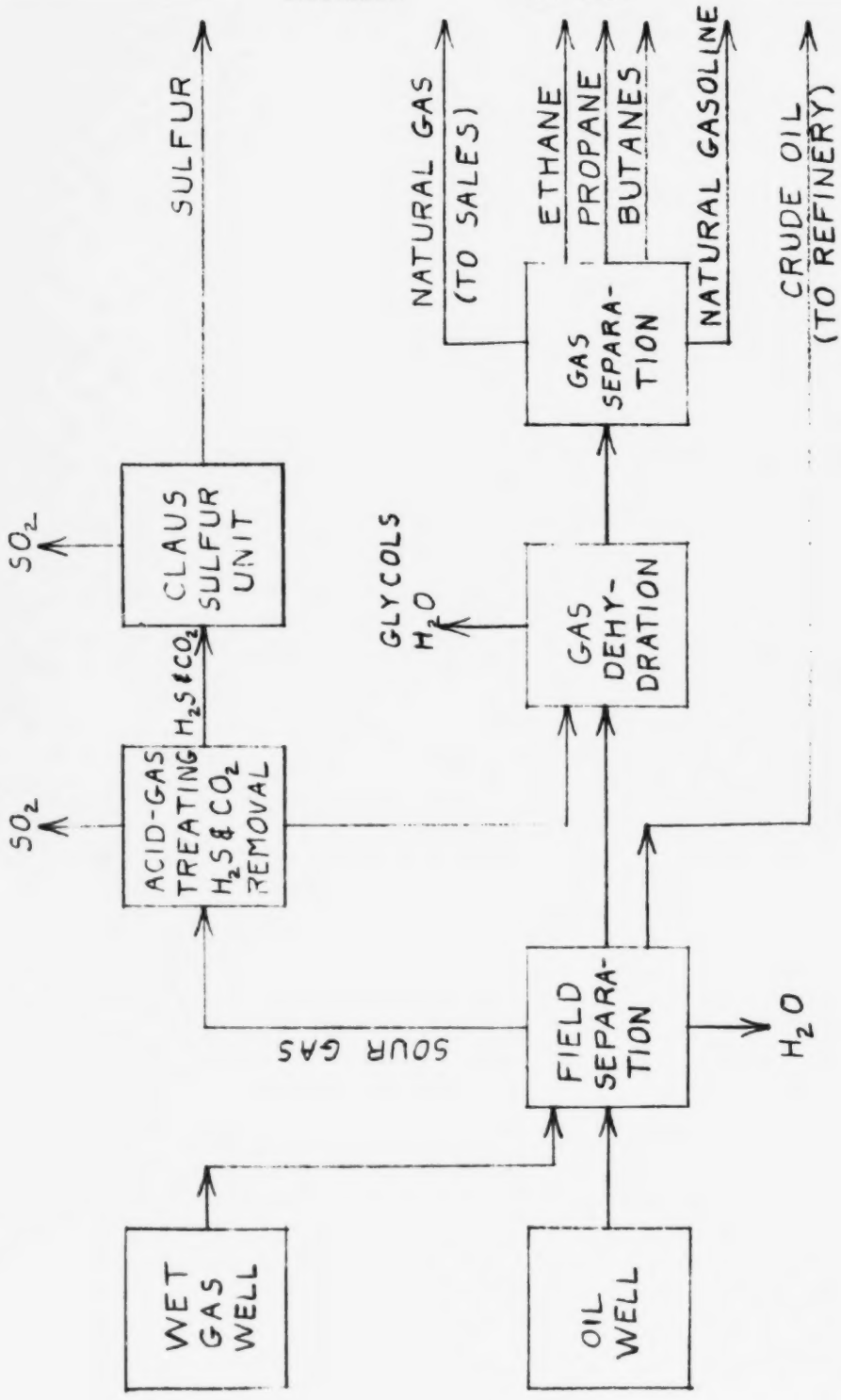
## APPENDIX E - PROCESS FLOW SHEETS

PR 109

Job E.P.A.
Location DURHAM, N.C.
Subject

**PROCESSES RESEARCH, INC.**
INDUSTRIAL PLANNING AND RESEARCH
CINCINNATI NEW YORK

File No 03410 Sheet No E-1
Checked by Date
Computed by G.N.T. Date 12-1-1972



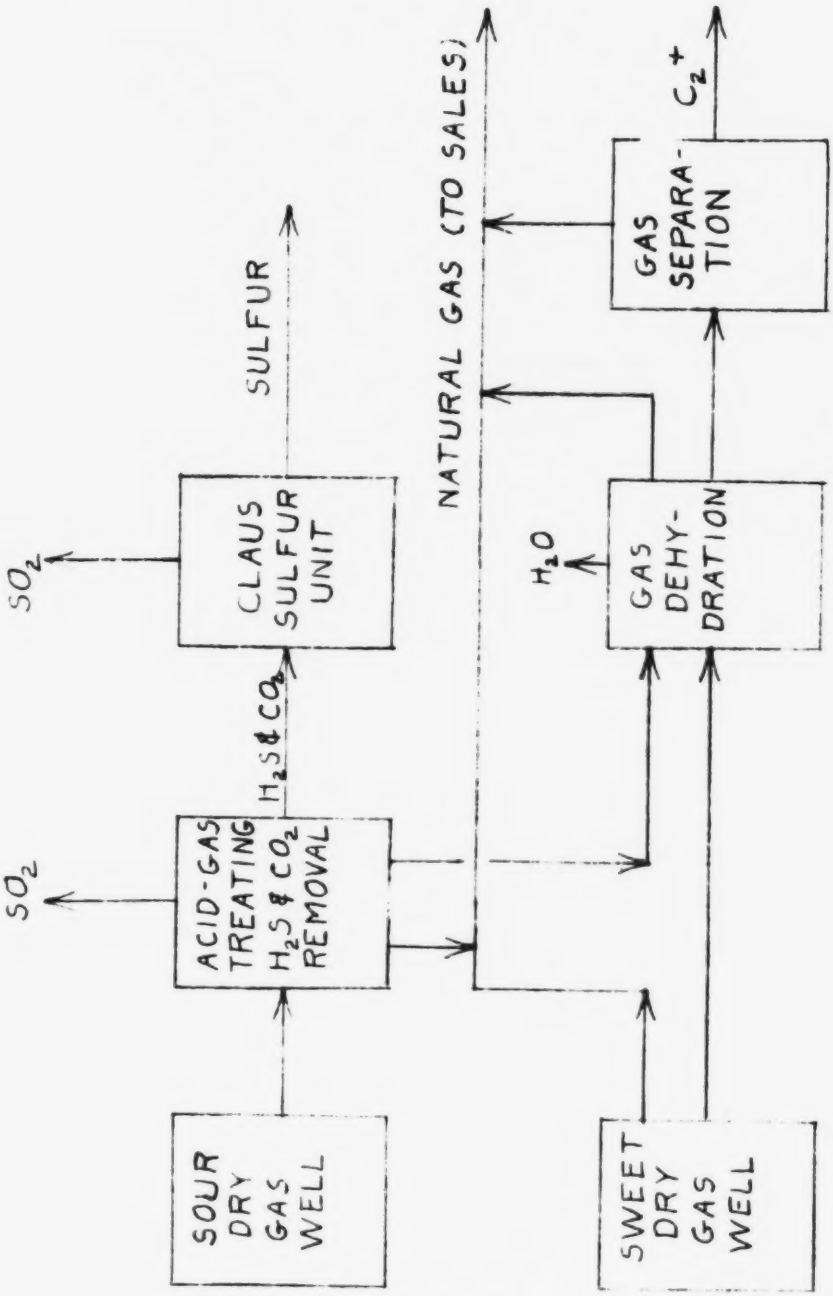

PROCESSING STEPS FOR THE PRODUCTION OF CRUDE OIL AND PURIFIED NATURAL GAS FROM OIL WELLS AND WET GAS WELLS

PR 109

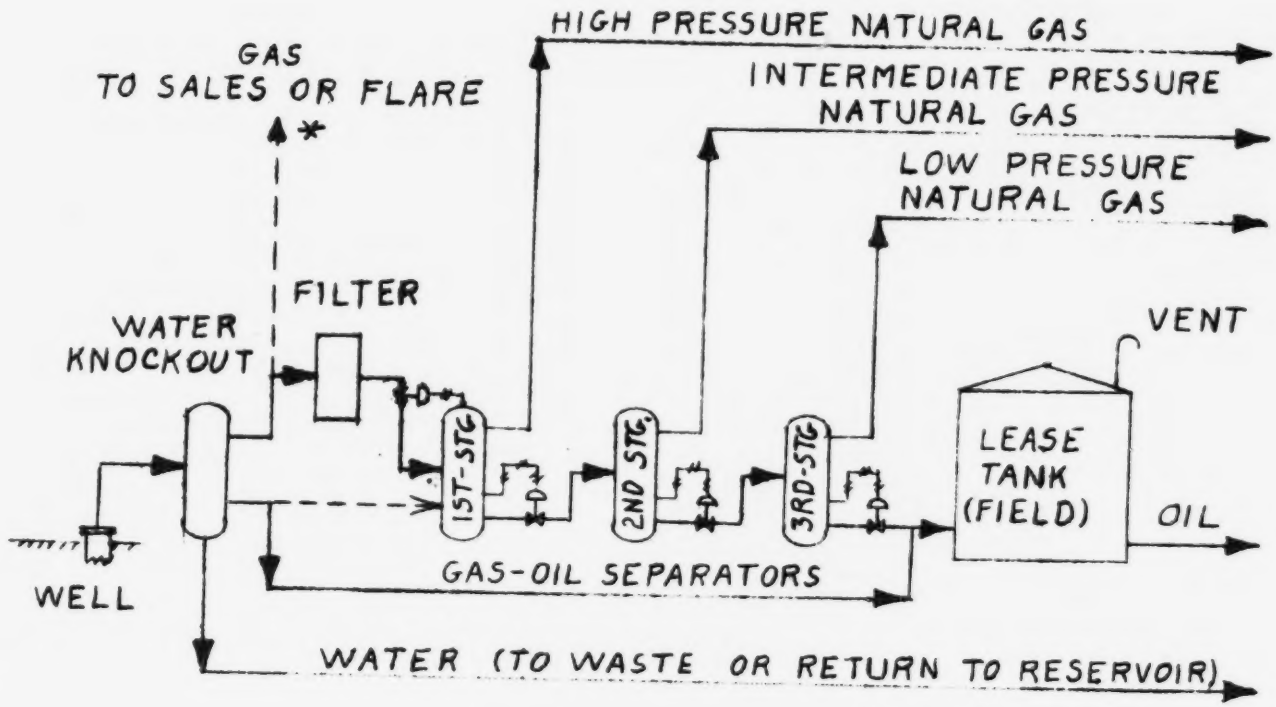
Job E.P.A.
Location DURHAM, N.C.
Subject

**PROCESSES RESEARCH, INC.**
INDUSTRIAL PLANNING AND RESEARCH
CINCINNATI NEW YORK

File No 03410 Sheet No E-2
Checked by Date
Computed by G.N.T. Date 12-1-1972




PROCESSING STEPS FOR PURIFICATION OF NATURAL GAS FROM DRY GAS WELLS




NOTE: REFERENCE, 49, PAGES 504-509 (EXCEPT *)
*REFERENCE, 41

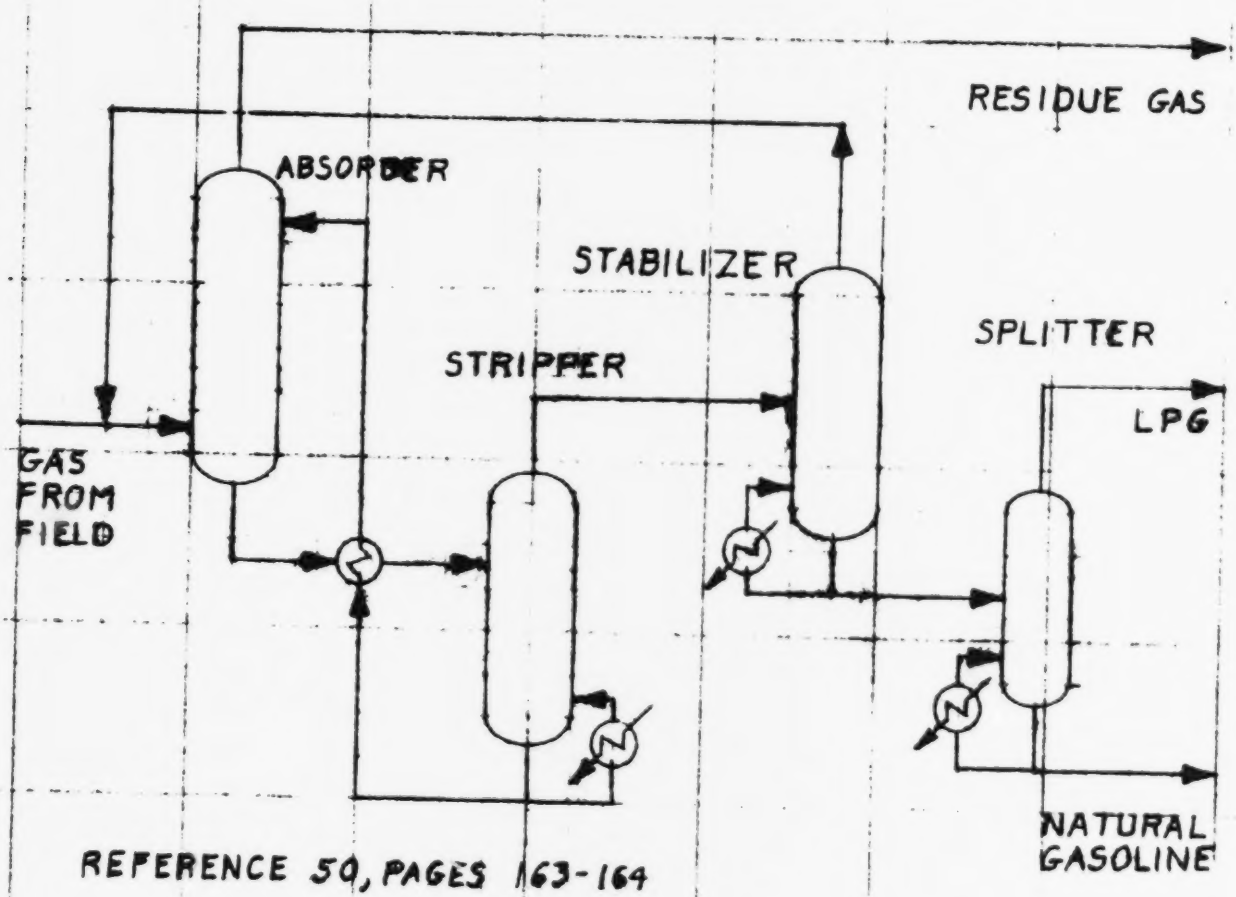
FLOW DIAGRAM FOR THREE-STAGE WELLHEAD SEPARATION UNIT

PR 109

Job E.P.A.
Location DURHAM, N.C.
Subject

PROCESSES RESEARCH, INC.
INDUSTRIAL PLANNING AND RESEARCH
CINCINNATI NEW YORK

File No 03410 Sheet No E-4
Checked by Date
Computed by G.N.T. Date 11-15-72



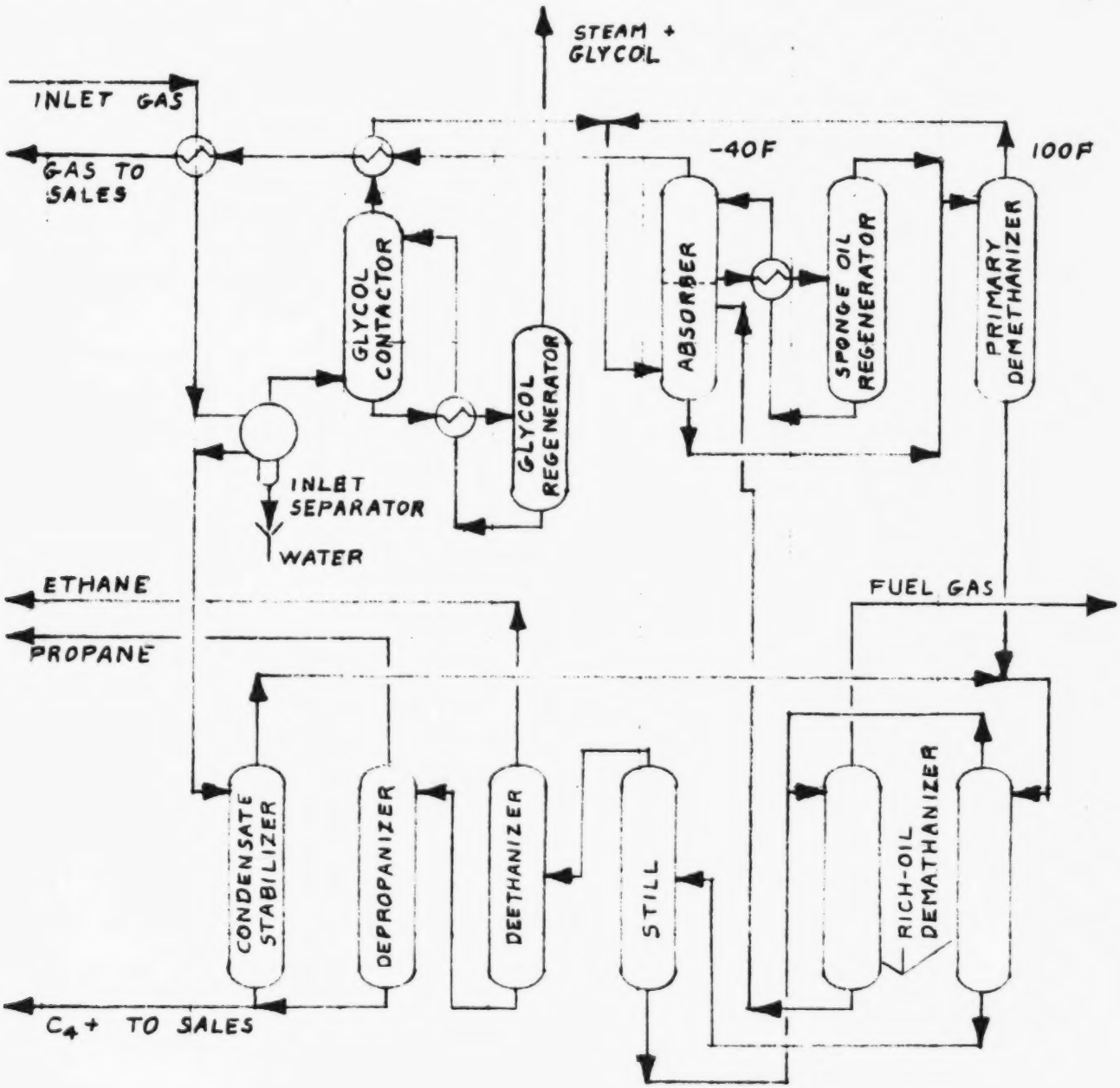

REFERENCE 50, PAGES 163-164

NATURAL GAS PROCESS "A"
ABSORPTION PLANT FOR NATURAL GASOLINE

Job E.P.A.
Location DURHAM, N.C.
Subject

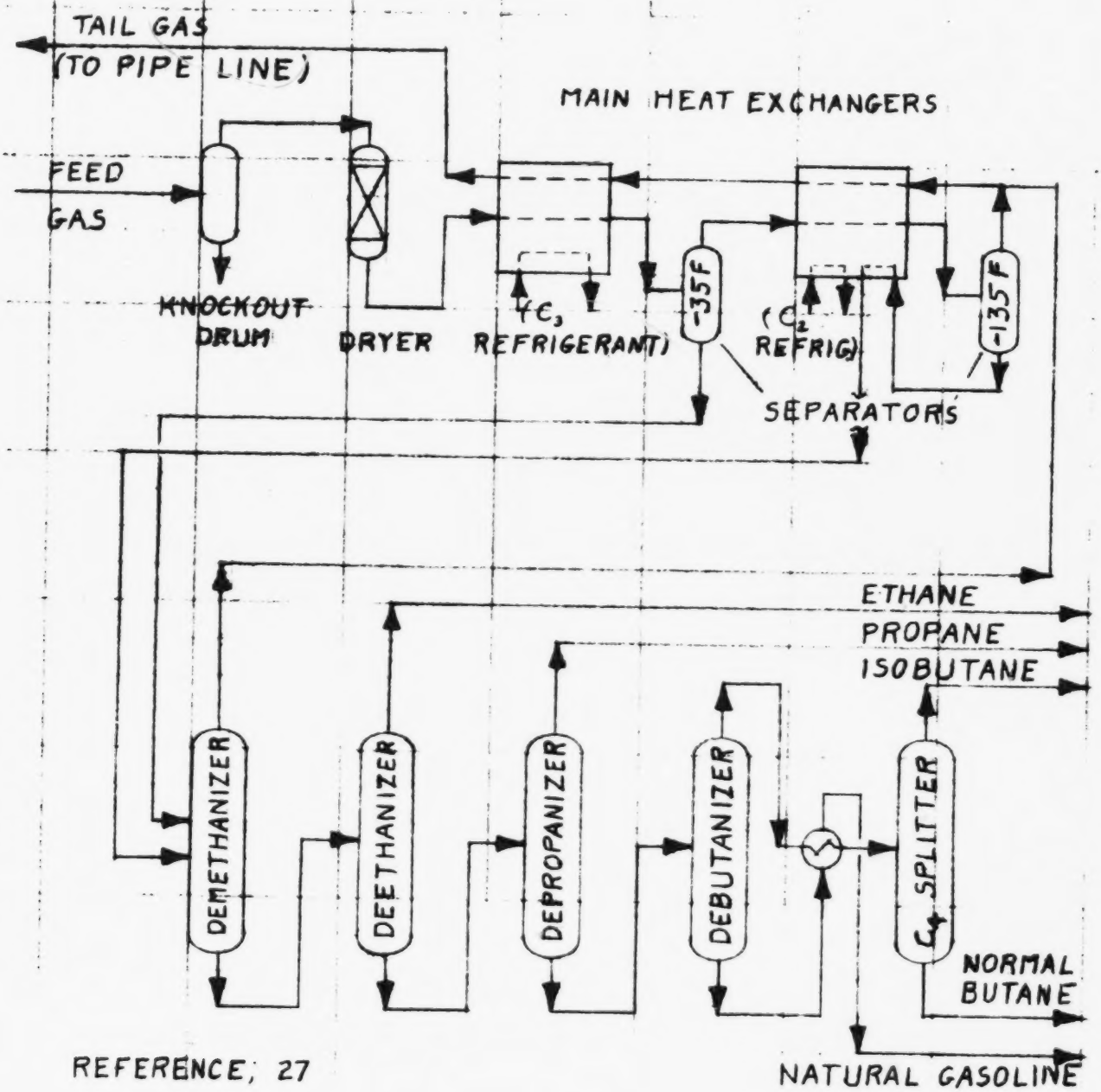
PROCESSES RESEARCH, INC.
INDUSTRIAL PLANNING AND RESEARCH
CINCINNATI NEW YORK

File No 03410 Sheet No E-5
Checked by Date
Computed by GNT Date 11-16-1972




REFERENCE; 24

NATURAL GAS PROCESS "B"
REFRIGERATED ABSORPTION PROCESS



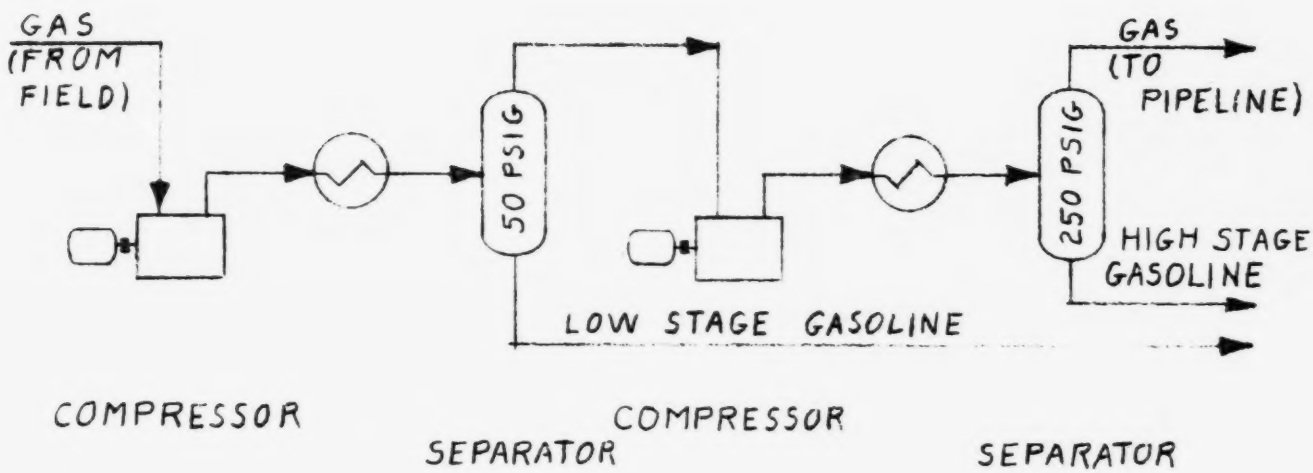

REFERENCE; 27

NATURAL GAS PROCESS "C"
REFRIGERATION PROCESS

Job E.P.A.
Location DURHAM, N.C.
Subject

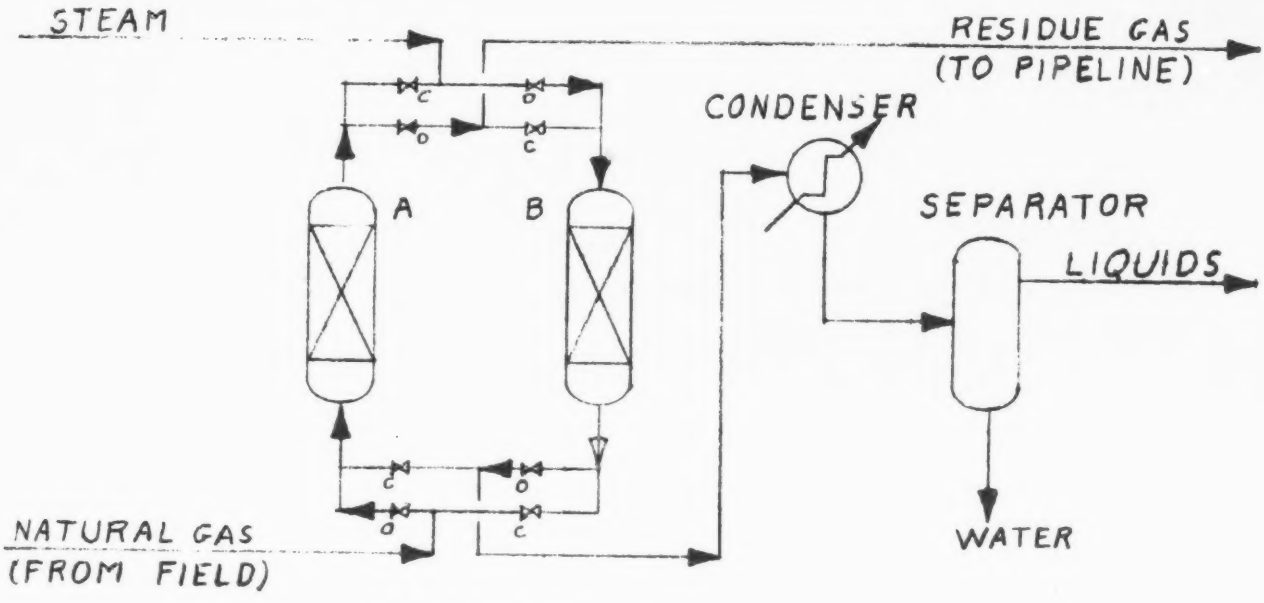
**PROCESSES RESEARCH, INC.**
INDUSTRIAL PLANNING AND RESEARCH
CINCINNATI NEW YORK

File No 03410 Sheet No E-7
Checked by Date
Computed by G.N.T. Date 11-17 1972




REFERENCE, 53 , PAGE 2-4

NATURAL GAS PROCESS "D"
COMPRESSION PROCESS




ADSORBERS

NOTE: FLOWS AND VALVE POSITIONS ARE SHOWN FOR ADSORBER "A" ON STREAM AND ADSORBER "B" ON REGENERATION.
REFERENCE, 50, PAGES 154-155

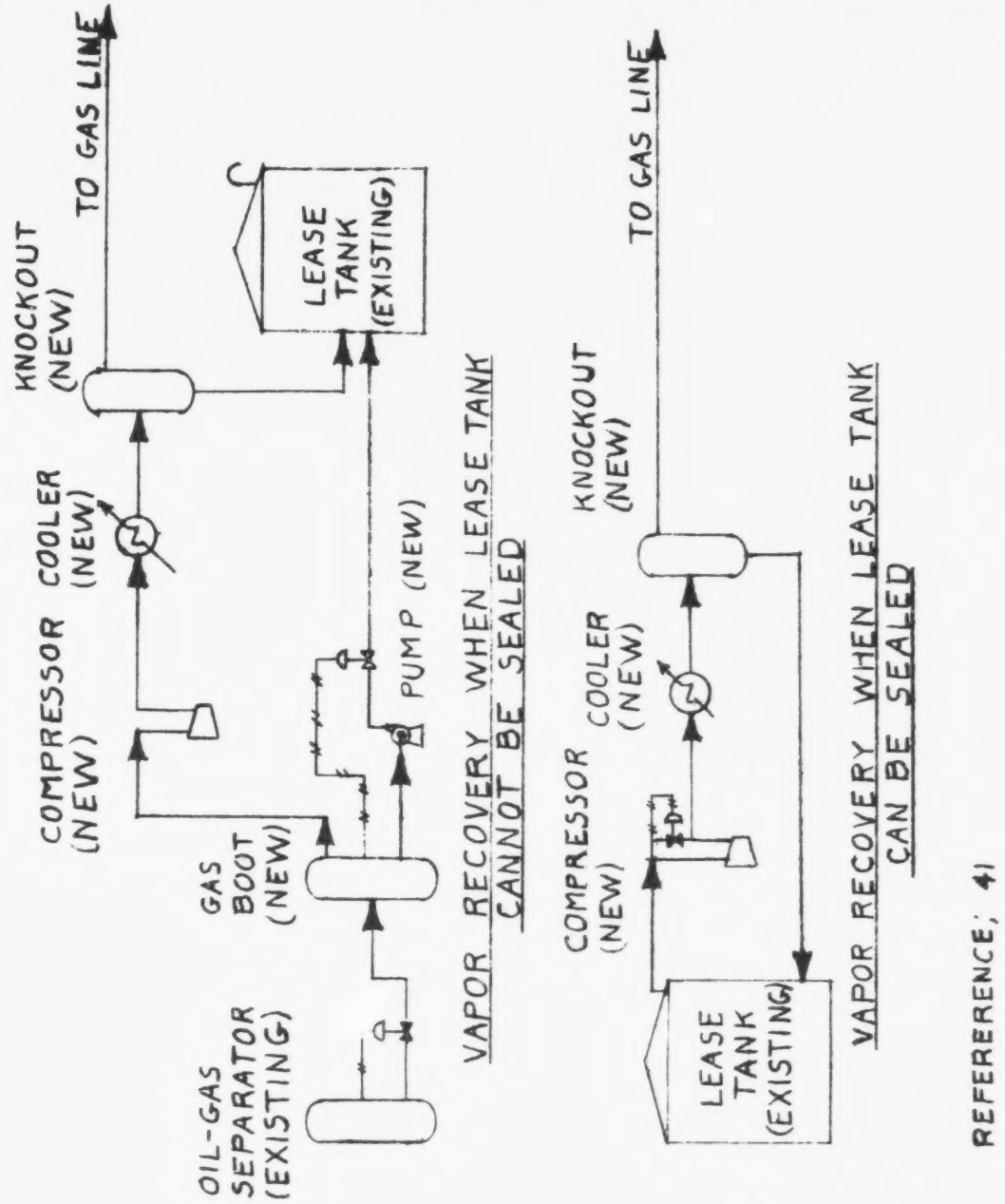
# NATURAL GAS PROCESS "E"
# ADSORPTION PROCESS

## APPENDIX F - EMISSIONS CONTROL PROCESS FLOW SHEET

Job E.P.A.
Location DURHAM, NC.
Subject

PROCESSES RESEARCH, INC.
INDUSTRIAL PLANNING AND RESEARCH
CINCINNATI NEW YORK

File No 0341J Sheet No E-1
Checked by Date
Computed by GNT. Date 12-1-1972




REFERENCE; 41

EMISSIONS CONTROL EQUIPMENT FOR
CRUDE OIL FIELD PROCESSING

## APPENDIX G - STATE AIR POLLUTION LAWS AND REGULATIONS

Table G-1 Government Agencies Authorized by State Law to Enact and Enforce Air Pollution Control Regulations

Table G-2 State Air Pollution Control Regulations

# TABLE G-1

Job EPA | PROCESSES RESEARCH, INC. | File No 03410 Sheet No 1
Location DURHAM N.C. | INDUSTRIAL PLANNING AND RESEARCH | Checked by ____ Date ____
Subject ____ | CINCINNATI NEW YORK | Computed by GNT. Date 10-24 1972

## GOVERNMENT AGENCIES AUTHORIZED BY STATE LAW TO ENACT AND ENFORCE AIR POLLUTION CONTROL REGULATIONS

| STATE | DATE - LATEST ENACT-MENT(a) | AGENCY | | | |
|---|---|---|---|---|---|
| | | STATE | CITIES & TOWNS | COUNTIES | REGIONS |
| ALABAMA | 1971 | X | X | X | |
| ALASKA | 1971 | X | X | X | |
| ARIZONA | 1970 | | | X (b) | X (b) |
| ARKANSAS | 1965 | X | | | |
| CALIFORNIA | | X (c) | | | |
| COLORADO | 1971 | X | X | X | |
| FLORIDA | | X | X | X | |
| ILLINOIS | 1971 | X (c) | | | |
| INDIANA | 1969 | X | X | X | |
| KANSAS | 1970 | X | X | X | |
| KENTUCKY | 1970 | X | X | X | |
| LOUISIANA | 1969 | X | | | |
| MICHIGAN | 1965 | X | X | X | |
| MISSISSIPPI | 1972 | X | | | |
| MISSOURI | 1972 | X | X (d) | X (d) | |
| MONTANA | 1967 | X | X | X | |
| NEBRASKA | 1972 | X | X | X | |
| NEVADA | | X (e) | | X (e) | |
| NEW MEXICO | 1971 | X | X | X | |
| NEW YORK | | X | X | X | |
| NORTH DAKOTA | 1971 | X | X | X | |
| OHIO | 1971 | X (f) | X (f) | X (f) | X (f) |
| OKLAHOMA | 1970 | X | X | | |

# GOVERNMENT AGENCIES AUTHORIZED BY STATE LAW TO ENACT AND ENFORCE AIR POLLUTION CONTROL REGULATIONS

| STATE | DATE-LATEST ENACTMENT (a) | AGENCY | | | |
|---|---|---|---|---|---|
| | | STATE | CITIES & TOWNS | COUNTIES | REGIONS |
| PENNSYLVANIA | 1968 | X | X | X | |
| SOUTH DAKOTA | 1970 | X | X | X | |
| TENNESSEE | 1971 | X | X | X | |
| TEXAS | 1971 | X | X | | |
| UTAH | 1971 | X | X | X | |
| VIRGINIA | | X | X (9) | X (9) | X (9) |
| WEST VIRGINIA | 1961 | X | X | X | |
| WYOMING | 1967 | X | | | |

NOTES

(a) Reference 54.

(b) Counties or districts of counties enact and enforce regulations; these to be equal to or more restrictive than criteria established by State.

(c) State established districts for basis of establishing regulations.

(d) Cities may not have enforcement program in counties that have a program.

(e) Counties with population greater than 100,000 must establish air pollution control. Counties with less than 100,000 population may establish program. State regulates emissions in counties with no regulations.

(f) State Control Board may delegate enactment and enforcement responsibilities to local units.

(g) State Board may establish control districts, the regulations of a control district supersede any other local regulations in that district.

TABLE G-2

STATE AIR POLLUTION CONTROL REGULATIONS[a]



| STATE | EFFECTIVE DATE OF REGULATIONS | MAXIMUM NONMETHANE HYDROCARBONS CONCENTRATION | EMISSIONS CONTROL REQUIRED FOR VOLATILE ORGANICS TANKAGE & TRANSFER | VISIBLE EMISSIONS MAXIMUM SMOKE CONCENTRATION | BURNING OF PETROLEUM WASTES | MAXIMUM EMISSIONS RATES AND GROUND LEVEL CONCENTRATIONS | |
|---|---|---|---|---|---|---|---|
| | | | | | | $SO_2$ | $H_2S$ & MERCAPTANS |
| Alabama | January 1972 | AAQS[b] 160 $\mu g/m^3$[e] 3-hour | Crude petroleum field processing equipment is exempt | (d) | (d) | Sulfur recovery plant emissions; Existing: 0.16 lb ($SO_2$)/lb S[c] | (d) |
| Alaska | (d) | (d) | (d) | (d) | (d) | (d) | (d) |
| Arizona | -- | AAQS[b] 80 $\mu g/m^3$ (e) | Petroleum tanks, new or remodeled, must have submerged dip pipe inlet | (d) | Open burning is prohibited | Ground level concentration: 50 $\mu g/m^3$[e] annual average; 150 $\mu g/m^3$[e] 3-day average; 250 $\mu g/m^3$[e] 24-hour average; 850 $\mu g/m^3$[e] 1-hour average | (d) |
| Arkansas | January 1972 | (d) | (d) | Existing units: Ringelmann - 2; New units: Ringelmann - 1 | Open burning of waste hydrocarbons is permitted at remote locations under certain conditions[f] | Emissions: 0.20 ppm | (d) |
| California | (d) | (d) | | | | AAQS[b] 0.5 ppm; 1-hour average; 0.04 ppm; 2-hour average | AAQS[b] $H_2S$: 0.03 ppm, 1 hour |
| Colorado | (d) | (d) | (d) | (d) | (d) | (d) | (d) |
| Florida | February 1972 | AAQS[b] 160 $\mu g/m^3$[e] | (d) | Existing units: Ringelmann - 2 until July 1, 1972 then Ringelmann-1; New units: Ringelmann - 1 | Flaring of waste gases is permitted if visible emissions are not exceeded | Sulfur recovery plant emissions New: 0.004 lbs $SO_2$/lb sulfur[c] Existing: Same as for new by July 1, 1975 | (d) |
| Illinois | April 1972 | Emission: 100 ppm as equivalent methane | (d) | (d) | Open burning of waste gases is permitted, if no air pollution results | Emission: 2,000 ppm | $H_2S$ or mercaptans: 0.65 lbs in any 5 minutes |
| Indiana | December 1968 | (d) | (d) | Ringelmann - 2 | (d) | (d) | (d) |
| Kansas | (d) | (d) | (d) | (d) | (d) | AAQS[b] 43 $\mu g/m^3$[e] annual geo. mean; 215 $\mu g/m^3$[e] 24-hour average not to be exceeded by more than 1 sample/3 months; 1001 $\mu g/m^3$[e] 1-hour average never exceeded | (d) |

TABLE G-2

STATE AIR POLLUTION CONTROL REGULATIONS[a]



| STATE | EFFECTIVE DATE OF REGULATIONS | MAXIMUM NONMETHANE HYDROCARBONS CONCENTRATION | EMISSIONS CONTROL REQUIRED FOR VOLATILE ORGANICS TANKAGE & TRANSFER | VISIBLE EMISSIONS MAXIMUM SMOKE CONCENTRATION | BURNING OF PETROLEUM WASTES | MAXIMUM EMISSIONS RATES AND GROUND LEVEL CONCENTRATIONS | |
|---|---|---|---|---|---|---|---|
| | | | | | | $SO_2$ | $H_2S$ & Mercaptans |
| Kentucky | April 1972 | (d) | Volatile organics (V.P.> 1.5 psi): Tank > 40,000 gals to be totally enclosed, floating roof or have other emissions control 90% efficient vapor recovery required for 20,000 gal/day tank loading station | (d) | Open burning must be in smokeless flares only | Emission: 2,000 ppm | Emission: $H_2S$, 10 grains/100 cubic feet |
| Louisiana | January 1972 | AAQS[b] 160 $\mu g/m^3$[e] 3 hours, 6-9 AM | Volatile organics (V.P.> 1.5 psi): Tanks > 40,000 gals must have vapor emissions control device | Smoke from flares: Ringelmann - 2 | Outdoor burning at site is permitted if disposal is not possible by other legal means | Sulfur recovery plant emissions 0.01 lb ($SO_2$)/lb sulfur[c] Any source: $SO_2$; 2,000 ppm | All process gas streams containing sulfur compounds must be flared or burned |
| Michigan | 1967 | (d) | (d) | Ringelmann - 2 | (d) | (d) | (d) |
| Mississippi | May 1970 | (d) | (d) | AAQS[b] Ringelmann - 2 | Burning of oil and gas wastes at remote sites is permitted[g] | Ground level concentration: 0.5 ppm average - 60 minutes 0.11 ppm average - 3 days | (d) |
| Missouri | February 1972 | (d) | (d) | Existing sources: Ringelmann - 2 New sources: Ringelmann - 1 | Open burning of trade wastes is permitted[g] only in an emergency or when other disposal means are not feasible | Emissions concentration: Existing: 2,000 ppm New: 500 ppm Emission rate: 1,000 lbs $SO_2$/hr except when following is not exceeded in ambient air: 0.25 ppm for 1 hour, 1 hour/4 days maximum or 0.07 ppm/24 hours; 1 day/90 days maximum | Ambient air concentration: $H_2S$ 0.03 ppm by vol. in 30 minutes exceeded less than 2 times in 5 days, or 0.05 ppm by vol. in 30 minutes 2 times/year maximum |
| Montana | November 1968 except as noted | (d) | Effective dates: New: June 30, 1970 Existing: June 30, 1972 Tanks, 65,000 gallons or larger for petroleum liquids with V.P. above 2.5 psia. Must be totally enclosed, or have floating roof or other emissions control | Existing sources: Ringelmann - 2 New sources: Ringelmann - 1 | Open burning of trade wastes is permitted if no other disposal method is suitable | 2.0 ppm at any time 0.1 ppm 24-hour average | (d) |
| Nebraska | (d) | (d) | (d) | (d) | (d) | (d) | (d) |

TABLE G-2

STATE AIR POLLUTION CONTROL REGULATIONS[a]



| STATE | EFFECTIVE DATE OF REGULATIONS | MAXIMUM NONMETHANE HYDROCARBONS CONCENTRATION | EMISSIONS CONTROL REQUIRED FOR VOLATILE ORGANICS TANKAGE & TRANSFER | VISIBLE EMISSIONS, MAXIMUM SMOKE CONCENTRATION | BURNING OF PETROLEUM WASTES | MAXIMUM EMISSIONS RATES AND GROUND LEVEL CONCENTRATIONS | |
|---|---|---|---|---|---|---|---|
| | | | | | | $SO_2$ | $H_2S$ & MERCAPTAN |
| Nevada | February 1972 | AAQS[b] 160 $\mu g/m^3$[e] 3 hour 6 AM to 9 AM | Tanks 40,000 gallons and larger must be totally enclosed, have floating roof, or emissions control. Tanks less than 40,000 gallons to have emissions control where feasible | Emissions: Opacity 20% | Open burning prohibited, except by special permit | AAQS[b] $SO_x$ as equivalent $SO_2$ 60 $\mu g/m^3$[e] annual arithmetic mean 260 $\mu g/m^3$[e] max. 24-hour conc. 1300 $\mu g/m^3$[e] max. 3-hour conc. | (d) |
| New Mexico | March 1972 | AAQS[b] 0.19 ppm, 3 hour average | (d) | Ringelmann - 1 Ringelmann > 1 for <1 minute in 30 minutes. Oil well drilling rigs and oil well service rigs are excluded | Open burning permitted for gas wastes at compressor stations and oil and gas wells when necessary for safety | AAQS[b] 0.10 ppm max. 24-hour average 0.02 ppm max. annual arithmetic mean | AAQS[b] 0.003 ppm $H_2S$ max. 1-hour average |
| New York | February 1967 | (d) | (d) | Emissions: New sources, Ringelmann - 1 Existing sources, Ringelmann - 2 | (d) | AAQS[b] 0.10-0.15 ppm[b] 24-hour average 0.25-0.40 ppm[h] 1-hour average | AAQS[b] $H_2S$, 0.10 ppm, 1-hour average |
| North Dakota | (d) | AAQS[b] 160 $\mu g/m^3$[e]; 3-hour 6 AM to 9 AM | Tanks 65,000 gallons and larger must be totally enclosed or have floating roof or other emissions control. Loading facilities handling 20,000 gals per day require submerged fill lines or other controls (above for new only) | Emissions: Existing sources, Ringelmann - 2 New sources, Ringelmann - 1 | Open burning permitted[g] No organic compounds emissions except blowdown and emergency relief unless burned in smokeless flare | No emissions regulations for $SO_2$ are listed. Emission limits may be established if AAQS[b] is exceeded AAQS[b] $SO_2$ 60 $\mu g/m^3$[e] annual arithmetic mean 360 $\mu g/m^3$[e] 24-hour average; 1 year max. 715 $\mu g/m^3$[e] 1-hour average | Waste gases containing $H_2S$ must be burned or treated before release AAQS[b] $H_2S$; 45 $\mu g/m^3$[e] 30 minutes conc. not exceeded > 2 times/5 days. 75 $\mu g/m^3$[e] 30 minutes conc. not exceeded > 2 times |
| Ohio | February 1972 | AAQS[b] 126 $\mu g/m^3$[e] 3-hour arithmetic mean 6 AM to 9AM 331 $\mu g/m^3$[e] 24-hour arithmetic mean 1 day per year max. | (d) | Emissions, any stationary source, Ringelmann - 1 compliance by July 1, 1975 | Open burning is prohibited. Waste hydrocarbon gas streams except emergency reliefs must be flared | Sulfur recovery plant emissions 0.01 lbs $SO_x$/lb sulfur prod. Other sources $SO_2$ emission: Existing: 2,000 ppm New: 500 ppm | $H_2S$ emissions in excess of 100 grains per 100 scf. Must be removed before venting or burning |
| Oklahoma | As noted | (d) | Regulation 15, effective July 1, 1972 limits emissions from the lease atmospheric crude oil stock tank to 1.5% of stock tank volume or 25 cubic feet per barrel of stock tank oil | All sources; Ringelmann - 1 (effective April 15, 1971; compliance by October 15, 1972) | Open burning is permitted in isolated areas for spilled oil where other disposal means are not available (effective January 1, 1971) | Sulfur recovery plant emissions New: $SO_x$ as $SO_2$ 20 lbs/ton of sulfur | (d) |

TABLE G-2

STATE AIR POLLUTION CONTROL REGULATIONS[a]



| STATE | EFFECTIVE DATE OF REGULATIONS | MAXIMUM NONMETHANE HYDROCARBONS CONCENTRATIONS | EMISSIONS CONTROL REQUIRED FOR VOLATILE ORGANICS TANKAGE & TRANSFER | VISIBLE EMISSIONS MAXIMUM SMOKE CONCENTRATION | BURNING OF PETROLEUM WASTES | MAXIMUM EMISSIONS RATES AND GROUND LEVEL CONCENTRATIONS | |
|---|---|---|---|---|---|---|---|
| | | | | | | $SO_2$ | $H_2S$ & MERCAPTANS |
| Pennsylvania | March 1972 | (d) | Tanks larger than 40,000 gallons for organic liquids with V.P. of 15 psia or higher must be pressure tight or have other emissions control. Loading facilities loading 20,000 gals or more per day must have vapor recovery | Opacity: 20% for period or periods up to 3 minutes in any hour | Open burning; forbidden in any air basin; permitted elsewhere, with restrictions | Sulfur recovery plant emissions expressed graphically; i.e., 0.1 lbs $SO_2$/ton sulfur for 10 ton/day plant and 0.001 lbs $SO_2$/ton sulfur for 100,000 tons/day plant<br>Other source emissions $SO_x$ as $SO_2$ 500 ppm vol. | AAQS[b]<br>$H_2S$, 0.005 ppm, 24-hour<br>0.10 ppm, 1-hour |
| South Dakota | (d) | (d) | (d) | (d) | (d) | (d) | (d) |
| Tennessee | January 1972 | AAQS[b]<br>Primary & secondary<br>160 $\mu g/m^3$[e]<br>3-hours AM | (d) | Emission, Ringelmann - 1, for new sources as of August 9, 1969, and and existing sources by August 9, 1973 | Open burning of waste hydrocarbons from oil production or pipeline breaks at remote sites is permitted | Process emissions, $SO_2$<br>Existing: 2,000 ppm; by August 8, 1973. -- 500 ppm; by July 1, 1975. --<br>New: 500 ppm | (d) |
| Texas | As noted | (d) | Tanks for crude oil are exempt from emissions control (Effective Dec. 31, 1973) | No visible emissions from waste gas flares for more than 5 minutes in any 2-hour period (Effective Dec. 31, 1973) | Open burning of waste petroleum from exploration, development, or production is permitted at remote sites (Effective Jan. 1967) | (d) | (d) |
| Utah | January 1972 | AAQS[b]<br>160 $\mu g/m^3$[e] 3-hour 6 AM to 9 AM<br>Primary and secondary standards | (d) | Emissions<br>Existing sources: Ringelmann - 2<br>New sources: Ringelmann - 1 | Open burning, not permitted | (i) | (d) |
| Virginia | March 1972 | AAQS[b]<br>Primary and secondary, 160 $\mu g/m^3$[e]<br>3-hour 6 AM to 9 AM | Controls required only in areas where board designates excessive photochemical oxidant levels exist | Emissions:<br>All sources Ringelmann - 1 | Open burning not permitted. Hydrocarbon emissions, except accidental or emergency, must be burned in smokeless flare | Sulfur recovery plant emissions<br>Existing: 8,000 ppm[j] | Emission:<br>$H_2S$: 15 grains/100 cubic feet |
| West Virginia | As noted | AAQS[b]<br>Effective September, 1971. Primary and secondary<br>160 $\mu g/m^3$[e]<br>3-hour 6 AM to 9 AM | (d) | (d) | Open burning not permitted (Effective September 1969) | Sulfur recovery plant emissions 0.06 lbs $SO_2$/lb sulfur processed by June 30, 1975<br>Other sources: 2,000 ppm vol by June 30, 1975 | $H_2S$; 50 grains per 100 cubic feet by June 30, 1975 |

TABLE G-2

STATE AIR POLLUTION CONTROL REGULATIONS[a]



| STATE | EFFECTIVE DATE OF REGULATIONS | MAXIMUM NONMETHANE HYDROCARBONS CONCENTRATION | EMISSIONS CONTROL REQUIRED FOR VOLATILE ORGANICS TANKAGE & TRANSFER | VISIBLE EMISSIONS MAXIMUM SMOKE CONCENTRATION | BURNING OF PETROLEUM WASTES | MAXIMUM EMISSIONS RATES AND GROUND LEVEL CONCENTRATIONS | |
|---|---|---|---|---|---|---|---|
| | | | | | | $SO_2$ | $H_2S$ & MERCAPTANS |
| Wyoming | February 1972 | AAQS[b] Primary and Secondary, 160 $\mu g/m^3$[e] 3-hour 6 AM to 9 AM | (d) | Opacity: New Sources, 20% existing sources 40% | Open burning prohibited, except by special permit | AAQS[b] $H_2S$ 60 $\mu g/m^3$[e] annual arithmetic mean 260 $\mu g/m^3$[e] max. 24-hour conc. 1 year max. 1,300 $\mu g/m^3$[e] max. 3-hour conc. 1 year max. | AAQS[b] 70 $\mu g/m^3$[e] 30 minute average 2 times/year max. 40 $\mu g/m^3$[e] 30 minute average 2 times/5 days maximum |

(a) Reference 54.

(b) Ambient Air Quality Standard.

(c) Pounds of sulfur as equivalent $SO_2$, per pound of sulfur processed or produced.

(d) Not reported in reference.

(e) Micrograms per cubic meter.

(f) Open burning is permitted at the site of origin of waste hydrocarbons from oil exploration, development, or production or from natural gas processing plants or materials spilled or lost from pipeline breaks where, because of isolated location, such waste products cannot be reclaimed, recovered or disposed of lawfully in any other manner.

(g) A permit is required from the local air pollution control regulatory agency for open burning.

(h) Value differs for each of five air quality areas.

(i) New installations with a potential to emit sulfur oxides greater than 250 tons of sulfur per year, as gas or mist, shall install controls to limit discharge to less than 20 percent of input sulfur.

(j) Regulations also contain a table of mass emission rates based on sulfur production capacity.

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# APPENDIX I - PERSONS CONTACTED FOR INFORMATION

## APPENDIX I

## PERSONS CONTACTED FOR INFORMATION

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## APPENDIX J - CONFERENCE MEMORANDUMS

PROCESSES RESEARCH, INC.
NEW YORK CINCINNATI CHICAGO
W.O. 03410
Task Order No. 13
Contract No. 68-02-0242
Memo 1

CONFERENCE MEMORANDUM

Date: October 4, 1972

Place: Offices of Processes Research, Inc.

Client: Environmental Protection Agency
Control Systems Division
National Environmental Research Center

Present:

| | |
|---|---|
| Richard Atherton | Environmental Protection Agency |
| M. R. Jester | Processes Research, Inc. |
| C. M. Jones | Processes Research, Inc. |
| G. N. Thomas | Processes Research, Inc. |

Subject: Screening Report
Crude Oil Production

Notes by: G. N. Thomas

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Distribution: Richard Atherton - 5
Joseph A. McSorley - 2

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1. Environmental Protection Agency transmitted to Processes Research, Inc., a copy of APTIC literature search on petroleum processes.

2. EPA transmitted to PR a copy of Dun and Bradstreet computer print-out of gas and oil producers based on SIC numbers 1311, 1381 and 2911.

3. It was decided to use the API abstracts service as provided by The Petroleum Publishing Company, Tulsa, Oklahoma, to aid in the literature search. PR is to determine the subject(s) to be searched.

4. PR called attention to the probability that the major source of emissions from crude oil processing may be from tankage operated by a large number of small operators. Searching to date has not produced information that will quantify these losses.

5. The search has indicated 805 gas processing plants in the United States as of January 1, 1972. Therefore, it was decided that the list of producers would indicate the number of plants in each county and state where plants exist and no attempt will be made to indicate the population density around a given plant.

6. PR will attempt to locate and report on ten plants with good emission control. No attempt will be made to list all plants with good emission control.

7. It was decided that technology exists for control of emissions from gas and oil processing. Therefore, research should be required only as it relates to location of sources of uncontrolled emissions in producing fields.

GNT:fj

October 9, 1972

CONFERENCE MEMORANDUM

Date: November 6, 1972

Place: Telephone Conversation

Client: Environmental Protection Agency

Participants: Mr. Harris — Texas Railroad Commission, Austin, Texas
Telephone 512-475-4519

G. N. Thomas — Processes Research, Inc.

Subject: Screening Report
Crude Oil Production

Notes by: G. N. Thomas

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Distribution: Richard Atherton - 5
Joseph A. McSorley - 2

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1. Mr. Harris stated that field venting and flaring of natural and casinghead-gas is restricted by Texas Penal Codes.

2. All vented burnable waste gas from crude oil and gas production in Texas must be flared.

3. The Texas Railroad Commission prohibits flaring of natural gas in the field unless it is not economically feasible to put this gas to commercial use.

4. The first no-flaring orders were issued in 1947.

5. In 1971, 0.63 percent of the nine trillion cubic feet of natural gas produced in Texas was flared. The percent flared has been reduced year by year.

6. Mr. Harris is sending to PR a copy of the Texas Railroad Commission's regulations pertaining to crude oil and natural gas production. These regulations contain the applicable section of the Texas Penal Codes.

7. Mr. Harris stated that the operating cost for a single stage compressor is 4 to 5 cents per 1000 cubic feet of gas. If three stage compression is required, the cost is 15 cents. If any significant length of pipeline is required, the total cost for recovering the gas presently being flared exceeds the market price for the gas.

GNT:fj

November 8, 1972

CONFERENCE MEMORANDUM

| | | |
|---|---|---|
| Date: | November 6, 1972 | |
| Place: | Telephone Conversation | |
| Client: | Environmental Protection Agency | |
| Participants: | C. V. Hudson | Louisiana Department of Conservation<br>Baton Rouge, Louisiana<br>Telephone: 504-389-5161 |
| | G. N. Thomas | Processes Research, Inc. |
| Subject: | Screening Report<br>Crude Oil Production | |
| Notes by: | G. N. Thomas | |

Distribution: Richard Atherton - 5
Joseph A. McSorley - 2

1. The Louisiana Department of Conservation prohibits the venting of gas from any gas well and prohibits the venting of gas in excess of 2000 cubic feet per barrel of crude oil produced.

2. All vented gas must be flared.

3. The Louisiana Department of Conservation encourages all oil producers to recover all gas that is economically feasible including the gas where the costs equal the selling price. The present wellhead price for gas is 21 cents per 1000 cubic feet.

4. Mr. Hudson estimates that less than 1 percent of the gas produced in Louisiana is flared. Most of this flaring is at offshore oil wells where the cost of collecting is too high.

5. Louisiana gas is a sweet gas. Therefore, any $SO_2$ produced when this gas is flared is not considered to be a pollution problem.

GNT:fj

November 8, 1972

CONFERENCE MEMORANDUM

Date: November 6, 1972

Place: Telephone Conversation

Client: Environmental Protection Agency

Participants: J. R. Weddle — California Department of Conservation, Sacramento, California, Telephone: 915-445-9686

G. N. Thomas — Processes Research, Inc.

Subject: Screening Report
Crude Oil Production

Notes by: G. N. Thomas

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Distribution: Richard Atherton - 5
Joseph A. McSorley - 2

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1. California State law prohibits wastage of any natural gas. This is a conservation measure. Flaring is also prohibited.

2. There is some bubbling loss from field tanks.

3. The gas recovery from offshore wells is probably better than for the onshore wells.

4. The total losses of natural gas in California are probably less than 1/2 percent of the total gas produced. Included in this percentage are small quantities of gas that are collected on site and burned for tank heating or fed as fuel to gas engines.

5. In general, most odors around crude oil processing equipment are due to poor housekeeping, such as not cleaning up accidental spills. The Department of Conservation is promoting better housekeeping in the oil fields, even at isolated locations.

GNT:fj

November 8, 1972

PROCESSES RESEARCH, INC.
NEW YORK CINCINNATI CHICAGO

W.O. 03410
Memo 5

CONFERENCE MEMORANDUM

Date: November 6, 1972

Place: Telephone Conversation

Client: Environmental Protection Agency

Participants: D. Edinger — Division of Conservation of Oklahoma Corporation Commission, Jim Thorpe Building, Oklahoma City, Oklahoma 73105, Telephone: 405-521-2308

G. N. Thomas — Processes Research, Inc.

Subject: Screening Report
Crude Oil Production

Notes by: G. N. Thomas

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Distribution: Richard Atherton - 5
Joseph A. McSorley - 2

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1. There is no law or regulation in Oklahoma prohibiting venting or flaring of gases from crude oil production.

2. The Division of Conservation discourages the venting of large quantities of gas.

3. Economics usually dictate as to whether or not individual producers vent gases.

4. The amount of gases lost or vented as reported in the Minerals Yearbook, by the U. S. Bureau of Mines, is based on estimates by Mr. Edinger's Department. These are the best estimates available.

5. Any additional questions should be referred to Mr. S. Shakely of the Division of Conservation.

GNT:fj

November 8, 1972

PROCESSES RESEARCH, INC.
NEW YORK CINCINNATI CHICAGO

W.O. 03410
Task Order No. 13
Contract No. 68-02-0242
Memo 6

CONFERENCE MEMORANDUM

| | | |
|---|---|---|
| Date: | December 5, 1972 | |
| Place: | Offices of Processes Research, Inc. | |
| Client: | Environmental Protection Agency | |
| Present: | Richard Atherton | Environmental Protection Agency |
| | M. R. Jester | Processes Research, Inc. (Part-time) |
| | C. M. Jones | Processes Research, Inc. |
| | G. N. Thomas | Processes Research, Inc. |
| Subject: | Screening Report<br>Crude Oil Production | |
| Notes by: | G. N. Thomas | |

Distribution: Richard Atherton - 5
Joseph A. McSorley - 2

1. Very little information has been obtained regarding hydrocarbon emissions. PR can provide only a rough estimate. Mr. Atherton will advise PR on Thursday, December 7, 1972, if such an estimate should be attempted.

2. The flaring of gas and the emissions of hydrocarbons have been drastically reduced, in recent years, in the oil fields because the producers have found that it is to their economic advantage to recover gas that formerly was wasted.

3. PR indicated that air pollution control regulations have not been obtained for some of the states or from any local unit of government. EPA will send any local regulations they have.

4. No new information has been obtained on $SO_2$ or $H_2S$ emissions from crude oil production for the six states that have most of the sour gas in the United States. Two articles present information that permits the estimation of $SO_2$ emissions in the Jay Field in Florida.

GNT:pm

December 6, 1972

PROCESSES RESEARCH, INC.
NEW YORK CINCINNATI CHICAGO

W.O. 03410
Task Order No. 13
Contract No. 68-02-0242
Memo 7

CONFERENCE MEMORANDUM

| | | |
|---|---|---|
| Date: | March 19, 1973 | |
| Place: | Telephone Conversation | |
| Client: | Environmental Protection Agency | |
| Participants: | J. Walters | American Petroleum Institute<br>Washington, D. C. |
| | G. N. Thomas | Processes Research, Inc. |
| Subject: | Screening Report<br>Crude Oil Production | |
| Notes by: | G. N. Thomas | |

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Distribution: Richard Atherton - 5
Joseph A. McSorley - 2

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1. The western section of the crude oil pipeline maps which was ordered as part of the set of maps on November 1, 1972, has not been received by PR.

2. In expediting the five maps which they previously sent, API did not follow up on sending the missing map. If the missing map is in stock in Washington it will be sent immediately.

GNT:jt

March 20, 1973